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May 26, 2005

BY OVERNIGHT COURIER AND E-FILE

Mary L. Cottrell, Secretary Department of Telecommunications and Energy One South Station Boston, MA 02110

Re: Bay State Gas Company, D.T.E. 05-27

Dear Ms. Cottrell:

Enclosed for filing, on behalf of Bay State Gas Company ("Bay State"), please find Bay State's responses to the following information requests of the Department of Telecommunications and Energy:

AG-2-16	AG-2-34	AG-2-35	AG-2-36	AG-2-37	AG-2-38
AG-2-39	AG-2-40	AG-2-45	AG-2-46	AG-2-47	AG-2-50
AG-2-51					

Please do not hesitate to telephone me with any questions whatsoever.

Very truly yours,

Patricia M. French

cc: Caroline O'Brien Bulger, Esq., Hearing Officer (1 copy)
 A. John Sullivan, DTE (7 copies)
 Andreas Thanos, Ass't Director, Gas Division
 Alexander Cochis, Assistant Attorney General (4 copies)

COMMONWEALTH OF MASSACHUSETTS DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL D. T. E. 05-27

Date: May 26, 2005

Responsible: Danny G. Cote, General Manager

AG-2-16 Produce copies of all reports, memorandums and analysis related to the mains and services replacement program in the Company's service

territories prepared by outside experts.

Response: Attachment AG-2-16 (a) is a copy of a report produced by RJ Rudden

regarding Comparison of Industry Corrosion Leak Data to Bay State Gas

Company.

Attachment AG-2-16 (b) is a copy of a report produced by RJ Rudden

regarding Distribution Infrastructure Replacement.

The Company will supply the supporting workpapers to Attachment AG-2-

16 (b) in a supplemental response, as this is a bulk document.



MEMORANDUM

To: Patricia French, Bay State Gas Company

FROM: Ed Anderson, R.J. Rudden Associates

DATE: February 18, 2005

SUBJECT: Comparison of Industry Corrosion Leak Data to Bay State Gas Company

Executive Summary

At the request of Bay State Gas Company (BSG), R.J. Rudden Associates, a Black and Veatch Company (Rudden) has performed an analysis of BSG's Brockton Division (Brockton) bare and unprotected coated steel main corrosion leak data for the period 1993 through 2003, inclusive.

The purpose of this analysis was to test the hypothesis that, while Bay State Gas has been working diligently to replace its aging bare and unprotected coated steel mains, a higher level of effort and investment will be required by BSG to ensure that the Company's leak experience remains manageable and that reliability is maintained.

Brockton was selected for this analysis since it accounts for the highest level of bare and unprotected coated steel mains and corrosion leak activity of BSG's three operating divisions and because its distribution system is predominately a high pressure system.¹

Rudden's analysis utilized BSG's company wide annual leak data for its leak backlog² and leak management performance review and Brockton-specific information for its corrosion leak comparisons to national and regional companies³.

¹ A pipeline operating at high pressure will allow more gas to escape than on a low pressure pipeline with the same size corrosion hole. High pressure leaks, because of the larger volume of gas escaping the pipeline, will typically be detected earlier than under similar conditions on a low pressure pipeline.

² Leak backlog represents the number of leaks that have been identified but not repaired by year-end. As specified by the DOT, the leak backlog data reported to the DOT include only the more serious Grade 1 and Grade 2 leaks. See Appendix C for a definition of Grade 1 and Grade 2 leaks.

³ See Appendix A for a listing of the national companies used in the comparison, and Appendix B for the list of regional companies.

Rudden has utilized Brockton specific U.S. Department of Transportation Office of Pipeline Safety (DOT) annual distribution mains and leak-related data. For comparisons to national and regional companies, we have used DOT annual distribution mains and leak-related data.

The focus on corrosion leaks is important because industry studies demonstrate that "when a section of pipeline system starts to develop leaks, experience has shown that further leaks will develop at a continuously increasing rate." Furthermore, it is Rudden's experience that corrosion leaks on underground non-cathodically protected (unprotected) bare and coated steel pipe can be expected to increase over time until the pipes are either brought under cathodic protection, retired or replaced.

Noteworthy findings and observations related to Rudden's analysis of BSG leak data compared to national and regional companies include:

- During the period reviewed by Rudden (i.e., 1993 to 2003), Bay State Gas has managed its leak repairs and end of year leak backlogs significantly better than the average of national and regional companies. This opinion is based on the commonly utilized measure of the effectiveness of a utility's leak management program referred to as the Leak Backlog/Repair Ratio. This ratio represents the number of leaks in backlog at year-end divided by the annual number of leaks repaired (not including third-party leaks).
 - BSG ranks very well in comparison to the national and regional companies using this ratio. Its performance is well within the first quartile of the companies included in the comparison.
 - o BSG has achieved this ranking while having to manage the increasing annual number of corrosion leaks within its Brockton Division.
- Brockton has experienced a 50% increase in corrosion leaks over the same period with 404 leaks in 1993 growing to 601 leaks in 2003. This increase in corrosion leaks has occurred while the Company has retired or replaced 31% of Brockton's bare and unprotected coated steel mains.
- A common industry benchmark of corrosion leak activity that is often utilized by
 the gas industry for comparison purposes among companies is the annual number
 of corrosion leaks per mile of bare and unprotected coated steel main. While BSG
 has replaced or retired 176 miles (31%) of Brockton's bare and unprotected coated
 steel mains since 1993, its annual number of corrosion leaks per mile of bare and

⁴ Peabody's "Control of Pipeline Corrosion," second edition 2001. Chapter 15, Page 290.

unprotected coated steel main since then has more than doubled from a level of 0.71 in 1993 to 1.54 corrosion leaks per mile in 2003.

- For the period reviewed, Brockton experienced a four times greater increase in the annual number of corrosion leaks per mile of bare and unprotected coated steel main when compared to the regional companies average number of annual corrosion leaks per mile of bare and unprotected coated steel main.
- Brockton's historical bare and unprotected coated steel main replacement efforts have not stemmed a continuing increase in BSG's corrosion leak rates as measured by corrosion leaks per mile of bare and unprotected coated steel main.

Summary of Findings

Based on BSG's Leak Backlog/Repair Ratio comparison to national and regional companies, BSG has demonstrated excellent leak management.

However, it is Rudden's opinion that BSG's efforts in replacing its aging bare and unprotected coated steel mains in the Brockton Division have not stemmed a continuing increase in Brockton's corrosion leaks. Furthermore, this is a signal that BSG needs to invest more resources in its bare and unprotected coated steel replacement efforts, in order to keep up with the problems and risks associated with its remaining bare and unprotected coated steel pipes.

This report is arranged in the following manner.

Section I - Purpose of Report - states the purpose and objectives of the report, including the analysis performed.

Section II - The Data - provides a listing and description of the data utilized in our analysis, as well as a discussion of various considerations and qualifications that should be understood in the use and interpretation of the data.

Section III - Findings and Opinions sets forth our conclusions, both objectively based on the data, and also from a judgmental, subject matter expertise perspective, based on the industry experience of the Rudden team.

Appendices –

- A. List of National Companies
- B. List of Regional Companies
- C. Glossary

Section I – Purpose of Report

BSG is preparing to request from the Massachusetts Department of Telecommunications and Energy (DTE) a rate adjustment mechanism for an accelerated bare and unprotected coated steel mains replacement program.

Such a program is believed to be necessary because, while BSG has been working diligently to replace its aging bare and unprotected coated steel mains, a higher level of effort and investment will be required by BSG to ensure that the Company's leak experience remains manageable and that reliability is maintained.

In addition, as part of BSG's preparation for the rate case, BSG determined it wanted to better understand how the BSG corrosion leak rates compare to national and regional companies.

The Brockton Division was selected for analysis due to its having the largest amount of bare and unprotected coated steel mains and corrosion leak activity on mains of BSG's three operating divisions and because its distribution system is predominately a high pressure system.

After a competitive bidding process, BSG engaged Rudden to perform the desired analysis.

Section II - The Data

This section identifies the data utilized in the analyses, discusses specific characteristics of the data that are relevant to the analysis, and advises on the use and interpretation of the information. In performing the analysis, Rudden utilized data from the DOT web site and from BSG's internal data systems, as well as Rudden's calculations using the data.

- **DOT Data** Gas distribution pipeline operators are required by DOT to annually submit certain main, service and leak data utilizing DOT form RSPA F7100.1-1. This data is available to the public through the DOT web site. (http://ops.dot.gov)
 - o The DOT data, as of August 24, 2004, included the following:
 - Data from 1993 to 2003
 - Miles of bare steel and unprotected coated steel mains
 - Number of corrosion leaks for mains
 - Number of total leaks
 - Number of leaks in backlog at year-end
 - Corrosion Leaks While DOT data provides the total number of corrosion leaks for mains, DOT does not provide a breakdown of the number of corrosion leaks by type of main material.
 - Due to this DOT data limitation, for the purposes of this review, we assumed that the reported corrosion leaks occurred solely on either bare steel or unprotected coated steel mains.
 - We believe that this assumption is reasonable since, while it is recognized that corrosion leaks can occur on protected coated steel mains, most corrosion leaks occur on bare steel and unprotected coated steel. Also,
 - Mains that are cathodically protected, while they occasionally develop corrosion leaks, are generally protected from corrosion leaks.
 - Cast iron main leaks are typically not caused by corrosion and are generally reported as other leaks (joint leaks) or outside force (main break leaks).
 - Plastic mains do not corrode.

- **BSG Data** Since the DOT data is reported on a company wide basis, BSG provided Brockton Division bare and unprotected coated steel main and leak-related data including:
 - o Data from 1993 to 2003.
 - o Miles of bare and unprotected coated steel mains.
 - o Number of corrosion leaks for mains.
- *Rudden Calculations* Utilizing BSG and DOT data, Rudden determined the:
 - o Annual change in bare and unprotected coated steel mains inventory.
 - o Ratio of the number of leaks in backlog at year-end per the annual number of total leaks repaired (not including third-party leaks). This is referred to as the Leak Backlog/Repair Ratio.
 - o Annual number of corrosion leaks per mile of bare and unprotected coated steel main.

Observations Regarding The Data:

- The DOT database contained data for 1,291 companies.
- Most of the companies that filed do not have bare steel mains or have a very small amount of bare steel mains compared to BSG.
- DOT Database Sorting Criterion Rudden utilized a sorting criterion intended to limit the focus to companies with a significant amount of bare steel, yet still incorporate a reasonable sample of companies. The sorting criterion chosen was all companies with a minimum of 50 miles of bare steel in 2003. Additional data which reinforced the reasonableness of this sorting criterion included:
 - o Fifty miles represents approximately 10% of BSG's total miles of bare steel mains.
 - o Nationwide, 77 companies meet the 50 miles of bare steel sorting criterion. They are listed in Appendix A. These companies are generally larger companies with organizational structure, operating procedures and State regulatory review processes similar to BSG.
 - o The 77 nationwide companies meeting the sorting criterion represents 97% of the bare steel in the DOT 2003 database (50,205 miles out of 51,906 miles).
- Regional Analysis In addition to the national sorting criterion of 50 miles, Rudden determined that BSG data might also be reasonably compared to companies in close

regional proximity to BSG. Companies in these nearby states were thought to possibly experience more similar environmental characteristics (such as weather, soil and age of pipe material) than companies in other areas of the United States.

- o The regional states selected include: Connecticut, Massachusetts, Maine, New Hampshire, New Jersey, New York, Rhode Island and Vermont.
- o There are 21 companies that meet the sorting criterion and are located in the eight regional states. They are listed in Appendix B.

Enhancements to the DOT data:

- Rudden discovered that four companies, that met the selection criteria used in our
 analyses, were missing 2003 data in the DOT database. Rudden spoke on several
 occasions to the DOT staff about the missing data and they were not able to provide the
 data. Rudden then contacted each of the four companies directly to obtain their
 information and then added it to the 2003 data. The four companies were KeySpan
 Energy West, KeySpan Gas East, Providence Gas and National Fuel.
 - o KeySpan Energy West, KeySpan Gas East and National Fuel provided its data directly to Rudden.
 - Providence Gas (PG) provided its data directly to Rudden; however, its data was aggregated with affiliate companies and was not available for only PG. Therefore, Rudden used PG 2002 data for 2003.
- Colonial Gas Co Lowell Div. is not included in the analysis due to Rudden observing that its bare steel main data varied during the period and was less than 50 miles of bare steel in 7 out of the 11 years reviewed.

Section III - Findings and Opinions

1. Actual Corrosion Leaks on Mains Experience

A review of corrosion leak activity begins with a review of the absolute number of corrosion leaks experienced by the company. While there are several factors that influence the level of corrosion leaks, the actual annual number of corrosion leaks is an indication of the condition of the bare and unprotected coated steel mains. This is especially true as the number of miles of such mains in inventory is being reduced through the company's ongoing repair, replacement and retirement efforts (discussed further in Finding # 4).

Over the period reviewed by Rudden, BSG's Brockton Division has experienced a 50% increase in the annual number of corrosion leaks on mains from a level of 404 leaks in 1993 to 601 in 2003. This increase is illustrated on Chart # 1.

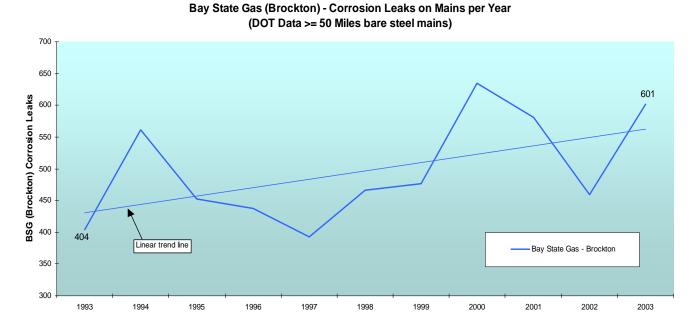


Chart # 1

- However, over the same period, the combined number of annual corrosion leaks on mains was decreasing for regional companies that met the selection criterion of greater than 50 miles of bare steel mains. This fact is illustrated on Chart # 2.
- It can be observed on Chart # 2, while the combined number of annual corrosion leaks on mains was decreasing for regional companies, Brockton's annual corrosion leaks on mains were increasing.

Comparison of Regional Companies to Bay State Gas (Brockton) - Corrosion Leaks on Mains per Year (DOT Data >= 50 Miles bare steel mains)

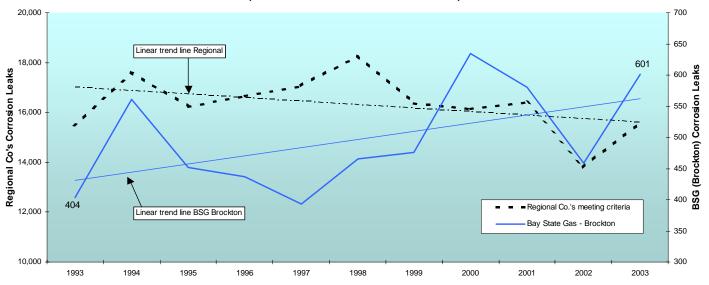


Chart #2

2. Management of End of Year Leak Backlogs

One measurement of natural gas utility leak management is the number of main and service leaks in backlog at year-end, while a snapshot, maintaining a lower level of leaks at year-end is particularly important in colder regions that may experience underground frost during the winter season.

Since 1993, based on DOT data, BSG on average ranked in the first Quartile (21%) for the number of leaks in backlog at year-end based on the comparison ranking of BSG vs. regional companies.

• This point is illustrated in Chart # 3, which compares BSG's annual percentile ranking of the number of leaks in backlog at year-end leak to regional companies for the period 1993 through 2003 that met the selection criterion of greater than 50 miles of bare steel mains.

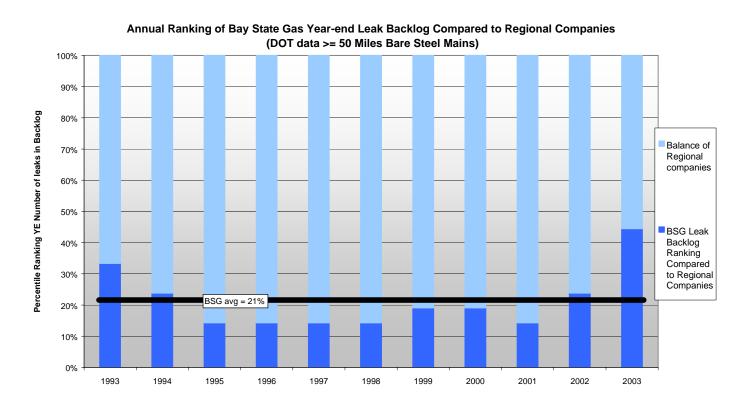
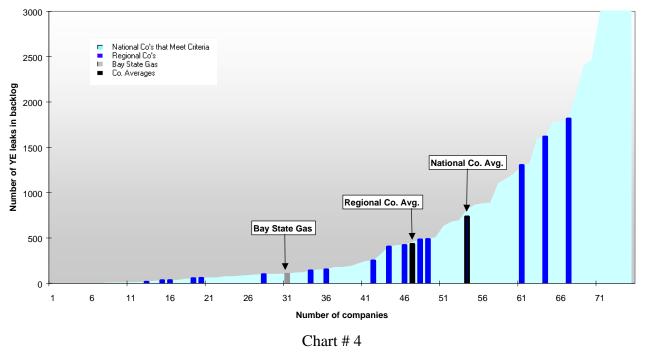


Chart #3

- In 2003, BSG experienced 550 more total main and service leaks than in 2002.
 - o These leaks created an additional burden on BSG, which is reflected in its higher leak backlog in 2003 compared to prior years.
 - o In 2003, BSG ranked 31 out of the 74 national companies meeting the 50-mile sorting criterion in year-end leak backlog, with 101 leaks in backlog at year-end.⁵
- Still, in 2003, BSG maintained a favorable ranking compared to national and regional companies.
 - The national data for companies meeting the 50-mile sorting criterion ranged from 0 to 5,063 leaks in backlog and averaged 733 leaks in backlog. This point is illustrated on Chart # 4, which compares BSG's 101 leaks in backlog at yearend to all national and regional companies for 2003.
 - O The data for regional companies meeting the 50-mile sorting criterion ranged from 0 to 1,814 leaks in backlog and averaged 432 leaks in backlog at year-end. This point is also illustrated on Chart # 4.





⁵ The analysis includes 18 regional and 74 national companies in 2003. Leaks in backlog at year-end data were not available for Providence Gas, Public Service Electric and Gas and National Fuel.

3. Leak Management Performance

A key measurement of natural gas utility leak management performance in effectively maintaining leak inventories and keeping potentially hazardous leaks to a minimum, is the ratio of the number of leaks in backlog at year-end per the annual number of leaks repaired (not including third-party leaks). This has been referred to as the Leak Backlog/Repair Ratio.

Rudden calculated the Leak Backlog/Repair Ratio for all regional companies meeting the 50-mile sorting criterion. The following discusses our findings and conclusions.

• Since 1993, based on DOT data, BSG ranks well within the first Quartile with a Leak Backlog/Repair Ratio average of 17% compared to regional companies meeting the 50-mile sorting criterion. This point is illustrated on Chart # 5.

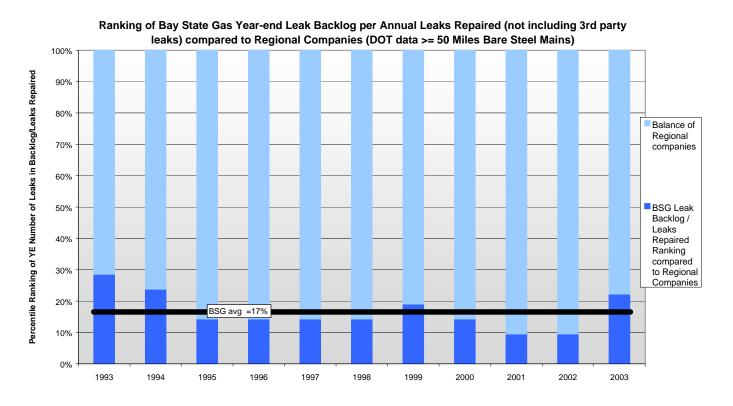


Chart #5

In 2003, BSG's management of leaks is much better than the average of national and regional companies meeting the 50-mile sorting criterion, based on the Leak Backlog/Repair Ratio.

- BSG has the fourth lowest Leak Backlog/Repair Ratio of 18 regional companies. BSG's Leak Backlog/Repair Ratio is 0.03 compared to the regional range of 0.00 to 0.62 and the regional company average of 0.20, as illustrated on Chart # 6.6
- BSG has the eighteenth lowest Leak Backlog/Repair Ratio of 74 national companies BSG's Leak Backlog/Repair Ratio is 0.03 compared to the national range of 0.0 to 2.86 and the national company average of 0.29, as illustrated on Chart # 6.

Comparison of National & Regional Companies - End of 2003 Leak Backlog per Annual Leaks Repaired (not including 3rd party leaks) - (DOT data >= 50 Miles Bare Steel Mains)

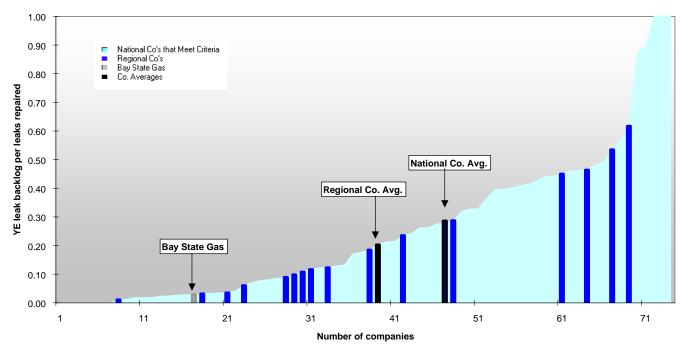


Chart #6

⁶ The analysis includes 18 regional and 74 national companies in 2003. Leaks in backlog at year-end data were not available for Providence Gas, Public Service Electric and Gas and National Fuel.

4. Managing Corrosion Leaks As Well As Bare and Unprotected Coated Steel Mains Replacements

• While BSG has either replaced or retired 176 miles (31%) of bare and unprotected coated steel mains in Brockton since 1993, its corrosion main leaks have grown from 404 in 1993 to 601 in 2003. This change equates to a 50% increase over 1993's level of corrosion main leaks and is illustrated on Chart # 7.

Bay State Gas (Brockton) Miles of Bare & Unprotected Coated Steel Mains Compared to Corrosion Main Leaks

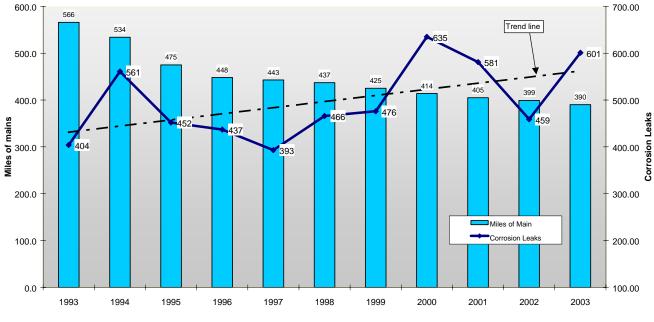


Chart #7

A common industry benchmark of corrosion leak activity that is often utilized by the gas industry for comparison purposes is the annual number of corrosion leaks per mile of bare and unprotected coated steel main.

• For the Brockton Division, this ratio has more than doubled from a yearly value of 0.71 in 1993 to 1.54 in 2003. This increase is illustrated on Chart # 8.

Bay State Gas (Brockton) Miles of Bare & Unprotected Steel Mains - Compared to Corrosion Leaks per Mile of Bare & Unprotected Coated Steel Mains

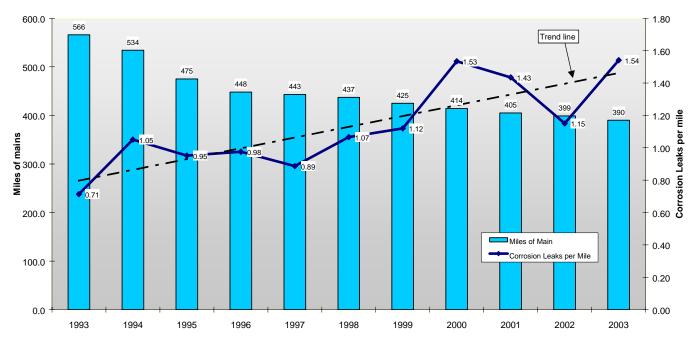


Chart #8

- Not withstanding BSG's better-than-average leak repair performance, it is Rudden's opinion that Brockton's historical bare and unprotected coated steel main replacements are not stemming a continuing increase in corrosion leak rates as measured by the annual number of corrosion leaks per mile of bare and unprotected coated steel main. This fact can be seen on Chart #8, which illustrates a 31% reduction since 1993, of Brockton's bare and unprotected coated steel main inventory due to main replacements and retirements. This can be compared to the more than doubling of the annual number of corrosion leaks per mile of bare and unprotected coated steel main.
- Furthermore, the fact that the annual number of corrosion leaks per mile of bare and unprotected coated steel main continues to increase while bare and unprotected coated steel mains inventory is being reduced, is noteworthy and a cause to consider the need for additional action.

5. Annual Number of Corrosion Leaks Per Mile of Bare and Unprotected Coated Steel Main - Comparison of Brockton to Regional and National Companies

- For the period 1993 through 2003, Brockton experienced a four times greater increase in the annual number of corrosion leaks per mile of bare and unprotected coated steel main than the average of regional companies meeting the 50-mile sorting criterion. Brockton's leak rate increased from 0.71 in 1993 to 1.54 in 2003.
- During the same period, regional companies experienced a much smaller increase in corrosion leak rates. The regional companies average of bare and unprotected coated steel mains corrosion leak rates increased from 0.73 to 0.93. This difference in the increase in leak rates of Brockton and the average of regional companies is illustrated on Chart # 9.

Comparison of Regional Companies to BSG (Brockton) - Corrosion Leaks per Mile of Bare & Unprotected Coated Steel Main (DOT Data >= 50 Miles bare steel mains)

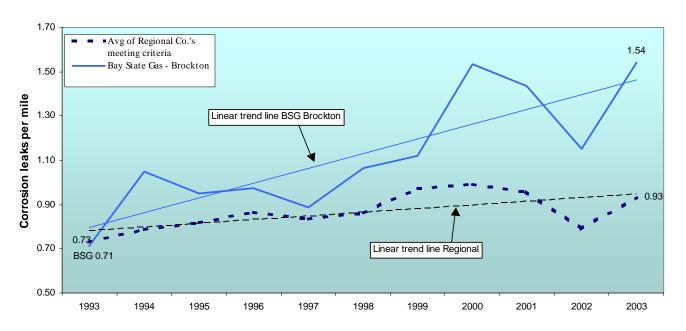
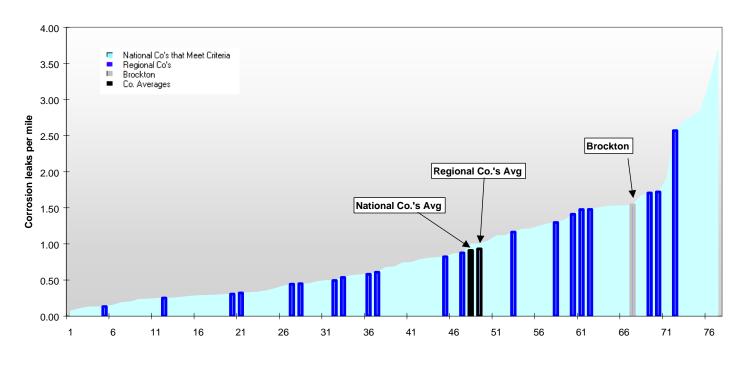


Chart #9

- In 2003, Brockton had a higher annual number of corrosion leaks per mile of bare and unprotected coated steel main than the average of national and regional companies meeting the 50-mile sorting criterion. This is illustrated on Chart # 10.
- Brockton ranked in the fourth quartile in comparisons to both national and regional companies on this measure. Specifically:
 - Brockton's annual number of corrosion leaks per mile of bare and unprotected coated steel main ranked 67 out of 77 national companies meeting the 50-mile sorting criterion in this measure.
 - Brockton's annual number of corrosion leaks per mile of bare and unprotected coated steel main ranked 18 out of 21 regional companies meeting the 50-mile sorting criterion in this measure.

These points are illustrated on Chart # 10

Comparison of National & Regional Companies to Bay State Gas (Brockton) - Corrosion Leaks per Mile of Bare & Unprotected Coated Steel Main (DOT 2003 data >= 50 miles of bare steel mains)



Appendix A

List of Companies Meeting Selection Criterion Within the National Sample

- 1. Arkansas Western Gas Co
- 2. Atlanta Gas Light Co
- 3. Baltimore Gas & Electric Co
- 4. Bay State Gas Co
- 5. Boston Gas Co
- 6. Cape Cod Gas Co (Div Of Colonial Gas Co)
- 7. Central Florida Gas Corp
- 8. Central Hudson Gas & Electric Corp
- 9. Chattanooga Gas Co
- 10. Cincinnati Gas & Electric Co
- 11. Clearwater Gas System, City Of
- 12. Colonial Gas Co Lowell Div
- 13. Columbia Gas Of Kentucky Inc
- 14. Columbia Gas Of Maryland Inc
- 15. Columbia Gas Of Maryland Inc
- 16. Columbia Gas Of Ohio Inc
- 17. Columbia Gas Of Pennsylvania
- 18. Columbia Gas Of Virginia Inc
- 19. Consolidated Edison Co Of New York
- 20. Consumers Energy Co
- 21. Consumers Gas Utility Co
- 22. Corning Natural Gas Corp
- 23. Delta Natural Gas Co Inc
- 24. Dominion East Ohio
- 25. Dominion Hope
- 26. Dominion Peoples
- 27. Equitable Resources (aka Equitable Gas Co)
- 28. Equitable Resources (aka Equitable Gas Co)
- 29. Florida Public Utilities Co
- 30. Indiana Gas Co Inc
- 31. KeySpan Energy West
- 32. KeySpan Gas East Corp
- 33. Lancaster Municipal Gas Co, City Of
- 34. Louisville Gas & Electric Co
- 35. Michigan Consolidated Gas Co (MichCon)
- 36. MidAmerican Energy Company
- 37. Midwest Energy Inc
- 38. Mountaineer Gas Co
- 39. National Fuel Gas Distribution Corp New York

- 40. National Gas & Oil Corp
- 41. New Jersey Natural Gas Co
- 42. New York State Electric & Gas Corp
- 43. Niagara Mohawk Power Corp
- 44. Northern Illinois Gas Co
- 45. Northern Indiana Public Service Co
- 46. Northern Utilities, Inc. (NH)
- 47. Nstar Gas Company
- 48. Oklahoma Natural Gas Co
- 49. Orange & Rockland Utility Inc
- 50. Pacific Gas & Electric Co
- 51. PECO Energy Co
- 52. Pensacola, Energy Services Of
- 53. Peoples Gas System Inc
- 54. Peoples Gas System Inc
- 55. Peoples Gas System Inc
- 56. Peoples Gas System Inc
- 57. Peoples Gas System Inc
- 58. Pg Energy
- 59. PPL Gas Utilities Corp
- 60. Providence Gas Co
- 61. Public Service Co Of Colorado
- 62. Public Service Electric & Gas Co
- 63. Puget Sound Energy
- 64. Roanoke Gas Co
- 65. Rochester Gas & Electric Corp
- 66. Semco Energy Gas Company
- 67. South Jersey Gas Co
- 68. Southern California Gas Co
- 69. Southern Connecticut Gas Co
- 70. Southern Indiana Gas & Electric Co
- 71. T W Phillips Gas & Oil Co
- 72. TXU Gas Company
- 73. Vectren Energy Delivery Of Ohio
- 74. Washington Gas Light Co
- 75. Western Resources Inc (aka KPL Co. Or Gas Service)
- 76. Western Resources Inc (aka KPL Co. Or Gas Service)
- 77. Yankee Gas Services Co

Appendix B

List of Companies Meeting Selection Criterion Within the Regional Sample

- 1. Bay State Gas
- 2. Boston Gas
- 3. Central Hudson Gas & Electric
- 4. Cape Cod Gas (Div Of Colonial Gas)
- 5. Consolidated Edison.
- 6. Corning Natural Gas
- 7. KeySpan Energy-West
- 8. KeySpan Gas East
- 9. National Fuel Gas Distribution New York
- 10. New Jersey Natural Gas
- 11. New York State Electric & Gas
- 12. Niagara Mohawk Power
- 13. Northern Utilities, Inc. (NH)
- 14. Nstar Gas
- 15. Orange & Rockland Utility Inc
- 16. Providence Gas
- 17. Public Service Electric & Gas
- 18. Rochester Gas & Electric
- 19. South Jersey Gas
- 20. Southern Connecticut Gas
- 21. Yankee Gas Services

Appendix C - Glossary & Primer

Following are definitions of key terms used in this report, as well as a discussion of some of the issues related to the terms.

• **Coatings**⁷ - A liquid, liquefiable, or mastic composition that, after application to a surface, is converted into a solid protective, decorative, or functional adherent film.

Coatings normally are intended to form a continuous film of an electrically insulating material over the metallic surface to be protected. The function of such a coating is to isolate the metal from direct contact with the surrounding electrolyte (preventing the electrolyte from contacting the metal) and to interpose such a high electrical resistance that the electrochemical reactions cannot readily occur.

• **Corrosion**⁸ - One general definition of corrosion is the degradation of a material through environmental interaction.

Metals corrode as a result of the natural process of chemical interactions with their physical environment.

A significant amount of energy is put into a metal when it is extracted from its ores, placing the metal in what is known as a "high-energy state." The ores are typically "oxides" of the metal such as hematite (Fe2O3), for steel. Oxides are of a "lower energy state" than the related metals. One principle of thermodynamics is that a material will always seek its lowest energy state. In other words, most metals are thermodynamically unstable and will tend to seek a lower energy state, which is an oxide or some other compound. The process by which metals convert to the lower-energy oxides is called corrosion.

Corrosion of most common piping and related materials at near-ambient temperatures occurs in aqueous environments and is electrochemical in nature. The aqueous environment is also referred to as the electrolyte and, in the case of underground corrosion, is moist soil. The corrosion process involves the removal of electrons (oxidation) of the metal (pipe) and the consumption of those electrons by some other reduction reaction, such as oxygen or water reduction. "Reduction" means a chemical reaction in which one or more electrons are transferred from one atom or molecule to another.

The site where the metal is being oxidized is referred to as the anode or anodic site. At this site, direct electric current (the electrons) flows from the metal surface into the electrolyte as the metal ions leave the surface. This current flows in the

⁷ Peabody's "Control of Pipeline Corrosion," second edition 2001.

⁸ Peabody's "Control of Pipeline Corrosion," second edition 2001.

electrolyte to the site where oxygen, water, or some other species is being reduced. This site is referred to as the cathode or cathodic site.

Cathodic Protection (CP)⁹ - is a procedure by which underground metallic pipe is protected against deterioration (rusting and pitting).

Specifically, cathodic protection is a technique to reduce the corrosion of a metal surface (for example, a pipeline) by making that surface the cathode and have another metal become the anode of an electrochemical cell.

The principal methods for mitigating corrosion on underground pipelines are external coatings and CP. A primary function of a coating on a cathodically protected structure is to reduce the surface area of exposed metal on the pipeline, thereby reducing the current necessary to cathodically protect the metal.

CP is defined as "a reduction of the corrosion rate by shifting the potential of the structure toward a less oxidizing potential by applying an external current."

Applying an external current can be achieved by means of an external power source (referred to as impressed current CP) or by utilizing a sacrificial anode. The impressed current system uses a power supply, referred to as a rectifier and an anode buried in the ground to impress a current on the structure.

The more commonly used sacrificial anode system uses the galvanic relationship between a sacrificial anode material, such as zinc or magnesium and the pipe steel to supply the required CP current. The most common method of applying CP by natural gas utilities is through the use of sacrificial anodes.

In the case of a sacrificial anode system, the galvanic relationship between a sacrificial anode material, such as zinc or magnesium and the pipe steel is used to supply the required CP current.

- Gas leak grades that are reported to the Department Of Transportation (DOT) on form RSPA F7100.1-1 include all Grade 1 and 2 leaks. 10 BSG defines such leaks as Class 1 and 2.11
 - A Grade 1 or Class 1 gas leak "represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous."

¹⁰ Gas Piping Technology Committee (GPTC) ANSI Z380.1 "Guide For Gas Transmission and Distribution

⁹ Peabody's "Control of Pipeline Corrosion," second edition 2001.

Piping Systems," Guide Material Appendix G-192-11 defines Grades 1, 2 & 3 gas leaks.

¹¹ Bay State Gas Company Operating Procedures number 14.05 defines Class 1, 2 & 3 gas leaks.

- A Grade 2 or Class 2 gas leak are "recognized as being non-hazardous at the time of detection, but requires scheduled repair based on future hazard."
- A Grade 3 or Class 3 gas leak are not reported to the DOT as they are defined as "non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous."
- Gas leak classifications are defined in the Gas Piping Technology Committee (GPTC) ANSI Z380.1 "Guide For Gas Transmission and Distribution Piping Systems." The Guide Material is commonly utilized by gas operators and State Regulators including the Commonwealth of Massachusetts as an interpretation of "DOT 192 2003 CFR Title 49, Part 192 Transportation Of Natural And Other Gas By Pipeline: Minimum Federal Safety Standards." BSG's Operating Procedures incorporate this gas leak grading system.
- DOT requires that the cause of leaks be reported as in the example below:

	Leaks Eliminated During the Year		
Cause	Mains	Services	
Corrosion			
Third party			
Outside force			
Construction defect			
Material defect			
Other			

- **Unprotected bare steel (BS)** refers to bare steel pipe that has no exterior coating and has no effective cathodic protection installed on the pipe.
- Unprotected coated steel (UPCS) refers to steel pipe with an exterior coating (intended to electrically isolate the steel from the surrounding electrolytes in the soil) and has no effective cathodic protection installed on the pipe.

Report to Bay State Gas Company

Regarding

Distribution Infrastructure Replacement

March 10, 2005

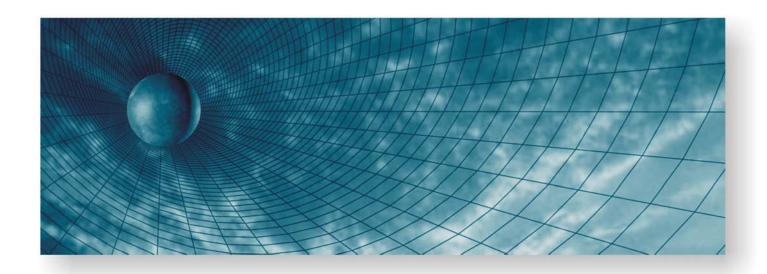








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SECTION I EXECUTIVE SUMMARY

PURPOSE

Bay State Gas Company ("BSG" or "the Company") engaged R.J. Rudden Associates, a Unit of Enterprise Management Solutions, Black & Veatch Corporation ("Rudden," or "we"), to evaluate the corrosion leak history of BSG's distribution system, and develop recommendations for the scheduling of the future replacement of non-cathodically protected bare steel mains and services and non-cathodically protected coated steel mains and services (collectively referred to later in this report as unprotected steel). 1.2

CONCLUSIONS & RECOMMENDATIONS

At BSG's current rate of replacement of unprotected steel of approximately 19 miles per year, it will require another 30 years to replace the 583 miles of unprotected steel main remaining on the system. With the last unprotected steel installed on the BSG system between 1955 and 1970,³ this implies a useful life for these materials of up to 80 years. Given the effects of corrosion on these materials, the recent leak history of BSG and the safety issues associated with natural gas pipe integrity, it is our opinion that the useful life of most, if not all, unprotected steel mains and services is significantly less than the implicit 80-year life. Based on current replacement rates, and discussions with both BSG staff and Heath Consultants (Heath),⁴ it is likely that the number of corrosion leaks per year will continue to increase and will challenge BSG's ability to effectively manage the risks associated with current replacement practices.

Based on interviews conducted with BSG personnel, as well as the accounting, engineering and reporting materials reviewed by Rudden, it appears that BSG has followed a prudent schedule of mains and services replacement, and has operated, monitored and maintained the existing system in a manner consistent with acceptable utility practices. Notwithstanding the application of good practices, the number of leaks has been increasing rapidly in recent years. The large increase in the number of leaks experienced by BSG in 2003 was accompanied by a large increase in the year-end leak backlog (i.e., those leaks that were still not repaired by year-end). This suggests that the rate of replacement needs to be accelerated if the growth of corrosion leaks are to be reduced to historical (or better) levels, and the overriding objective of minimizing the risks associated with

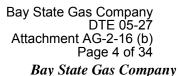
⁴ Heath Consultants were retained to provide operating and engineering advice on the project.



¹ Rudden competitively bid on this assignment in response to BSG's Request For Proposal dated April 30, 2004.

² Other pipe materials used on the BSG system, including wrought iron, cast iron, cathodically protected coated steel and plastic, were not included in this analysis.

³ The last dates of installation are approximately 1955 for non-cathodically protected bare steel and 1970 for non-cathodically protected coated steel.





unprotected steel pipe is to be achieved. Rudden expects the year-to-year leaks to continue to fluctuate in the future but still show a continually increasing, long-term trend based on our leak forecast described in this report, unless an accelerated replacement program is implemented.

Based on the analysis summarized in this report, Rudden recommends that BSG accelerate its current mains replacement schedule and replace the remaining unprotected steel mains in all divisions in as short a timeframe as practicable. This should be done considering the constraints of acceptable rate impacts and the coordination of construction with the municipal agencies. Since industry data indicates that unprotected services have degradation and corrosion characteristics comparable to unprotected mains, Rudden recommends that BSG replace all unprotected services connected to unprotected mains at the time of the main replacement. The concurrent replacement of services is consistent with standard industry practice and BSG's historical practice. This accelerated replacement is necessary if the Company is to ensure continued safe and reliable service to its customers in the future. Rudden believes the two shortest scenarios analyzed, 10 and 15 years, offer a reasonable approximation of a practicable, minimum replacement schedule.

BACKGROUND

It is important to acknowledge at the outset that the issues addressed in our study have two dimensions. The first and overarching dimension relates to the implications that our findings have for the continued safe and reliable operations of BSG's distribution system. The primary objective of the study, therefore, was to provide BSG with information and recommendations that will assist its management in the continued construction, operation and maintenance of a safe and reliable distribution system. The second and subsidiary dimension of the study was to evaluate the potential cost implications, for BSG and its customers, of alternative accelerated mains and services replacement programs, and to suggest possible alternative ratemaking and cost recovery options for such programs.

Unprotected steel pipe, including mains and services, is well known in the industry to have corrosive properties that result in an increasing number of leaks as pipes age. Industry studies have shown that "when a section of pipeline system starts to develop leaks, further leaks will develop at a continuously increasing rate," (see Chart 1-1 which follows for a graphical representation of this phenomenon that depicts the expected leak progression on an unprotected steel pipe with no replacement). In 2004, BSG determined that it needed to study its unprotected steel pipe plans, including the potential implications for the Company's leak repair and capital expenditure programs, as well as future customer rate impacts.

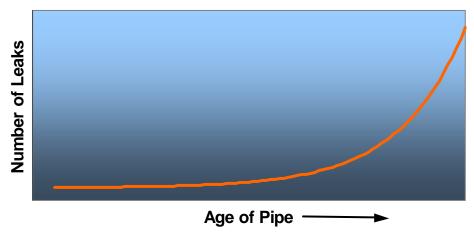
⁶ <u>Soil Corrosion and Pipe Line Protection</u>, Scott Ewing, Composed and Printed by William J. Ross, 1938, pages 46-50, based on data presented for service failures.



⁵ Peabody's "Control of Pipeline Corrosion," second edition, chapter 15, page 290, 2001.



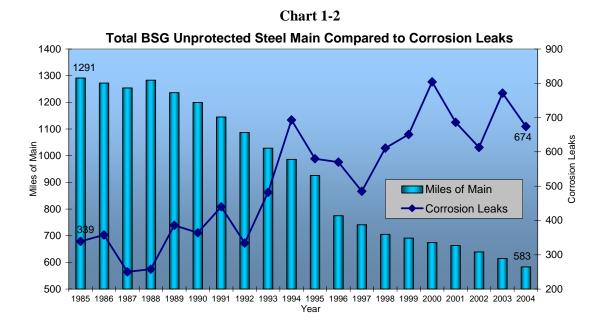
Chart 1-1 **Representative Corrosion Leak Rate Progression**



BSG has been replacing and retiring unprotected steel on its system since unprotected steel was first found to produce chronic and increasing corrosion leaks. BSG selects the specific pipe segments replaced each year based on each segment's historic leak rate and a number of other risk- and cost-related criteria. Even with the practice of replacing the worst segments each year, BSG's rate of corrosion leaks for unprotected steel mains has continued to increase due to the progressive deterioration of the unprotected steel pipe remaining in the ground. The data in Chart 1-2 illustrates that despite the current unprotected steel replacement rate (as evidenced by the declining total miles of unprotected steel mains shown by the vertical bars), the trend in leaks (the solid line) continues to increase. Chart 1-2 shows that while BSG has reduced the unprotected steel from 1,291 miles in 1985 to 583 miles in 2004, the number of corrosion leaks has climbed from 339 in 1985 to 674 in 2004. Rudden and BSG would expect even higher leak rate increases were BSG not replacing the worst pipe segments each year; ultimately, we would expect the corrosion leak characteristics to approach the curve represented in Chart 1-1.







Distribution Infrastructure Replacement

BSG has not installed unprotected steel in any of its three divisions since approximately 1970, making the newest unprotected steel in the ground approximately 35 years old. Based on the replacement rates of the last 5 years, it will take approximately 30 years to replace the remaining unprotected steel. Neither BSG nor Rudden believes continuing with the recent historic replacement rate provides an acceptable course of action. In addition, BSG engineering personnel believe that the acceleration of growth in the corrosion of these materials is challenging BSG's ability to continue to safely and reliably operate and maintain these aging system components, especially in the Brockton Division where the majority of these mains operate under high pressure. The cost of a program to replace all remaining miles of unprotected steel main and services in the BSG system is estimated at approximately \$289 million in 2005 dollars. The estimate of \$289 million is based on replacing 583 miles of unprotected steel main and replacing or modifying 62,500 services.⁷

⁷ The services to be modified include only those services connected to the unprotected steel mains including 29,520 services to be replaced, 7,380 plastic services to be tied-over, and 25,600 meters and regulators requiring movement to the outside of residences and buildings.





ANALYSIS

The analysis that Rudden performed included:

- 1. A review of BSG's system, operations, maintenance, leak prioritization process, and leak reporting and repair methods and experience.
- 2. An analysis of BSG's annual number of corrosion leaks, as well as the number of leaks per mile.
- 3. A comparison of BSG's corrosion leaks per mile relative to industry data compiled on the web site of the Department of Transportation, Office of Pipeline Safety (DOT).
- 4. An analysis of the leak backlog/repair ratio used to analyze: (a) BSG's leaks remaining at the end of each year (the "backlog"), to (b) the number of leaks repaired in the reporting year (not including 3rd party leaks).
- 5. A comparison of BSG's backlog ratio relative to industry data compiled on the web site of the DOT.
- 6. A forecast of leaks based on a statistical analysis of BSG historical data.
- 7. A financial analysis for a forecasted 40-year period that examined the potential costs to both customers and BSG under a series of alternative main and service replacement programs, ranging from 10 to 30 years in duration.

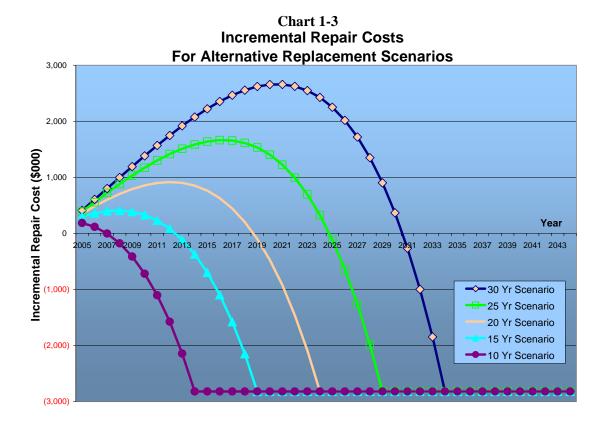
To perform the analyses related to historical leak experience and mains and services replacement, we gathered a variety of data and information on BSG operations using a combination of interviews with BSG personnel and a review of BSG documents. As previously indicated, we also performed projections of future requirements for unprotected steel mains and services replacement, as well as estimates of the economic impacts of present and future replacement programs. These economic analyses were performed under various business scenarios associated with alternative accelerated mains and services replacement programs. Among other analyses, we (a) projected the anticipated future reduction in leak repairs resulting from the use of plastic or cathodically protected coated steel for the replacements; and (b) forecasted the continuing leak increases for the remaining unprotected steel, as well as the related mains and services replacement costs. The leak forecast for the BSG unprotected steel piping ("leak forecast" refers to Rudden's forecast of leaks on the unprotected steel mains discussed in Section III) was based on linear and non-linear regression analyses. Rudden also enlisted the assistance of Heath, a firm recognized in the industry for its pipe corrosion and leak expertise, to confirm Rudden's conclusions regarding corrosion-related expectations of unprotected steel. Further, Heath was asked to review the reasonableness of our expectations regarding future corrosion and leak experience on the unprotected steel system. Using these inputs, Rudden developed an economic analysis for a forecasted 40-year period that examined the potential cost impacts on both customers and BSG under replacement schedules, varying in length of between 10 and 30 years. This analysis was performed in 5-year increments (with 30 years approximating the current replacement schedule based on the replacement experience during the last 5 years).

As the unprotected steel mains and services continue to degrade, Rudden forecasts that the costs of leak repairs on these pipes will continue to increase in proportion to the increasing leaks until the pipe is ultimately replaced or





retired. Chart 1-3 illustrates the impact of alternative replacement programs on the cost of repairs. Chart 1-3 depicts the forecasted incremental repair-related annual O&M costs relative to the levels experienced in 2004 (a negative value would represent an incremental savings). In addition, Chart 1-3 shows that only the shortest scenario of 10 years, offers the prospect of any near-term O&M savings.



This analysis used annual increases to the investigation and repair costs from the costs of 2004, i.e., the incremental costs.⁸ In addition, only those costs attributable to corrosion leak investigation and repair were used in this analysis. At the time of this analysis, BSG was contemplating a rate filing for an adjustment to base rates, with a test year of 2004. Rudden chose to use the incremental change from the end-of-year 2004 since it was thought all costs prior to January 2005 would be included in base rates.

⁸ As an example of the incremental cost, the investigation and repair costs for corrosion leaks in 2004 was \$2,819,000 for the 30-year scenario. The costs in 2005 were estimated at \$3,229,000, which accounted for the forecasted increase in the number of leaks and inflation adjustments. Only the incremental increase from 2004 to 2005, or \$410,000, was used in this analysis.





The results included estimates of the annual revenue requirements that would be required under a number of regulatory recovery scenarios, including recovery through:

- (a) Annual rate cases
- (b) Rate cases every three years
- (c) Recovery through a cost tracking mechanism with annual adjustments

The annual capital replacements (in 2005 dollars) and the miles of unprotected steel replaced in each of the scenarios are shown in Table 1-2 below:

Table 1-2
Annual Miles & Cost of Bare Steel Capital Replacements

	Program Duration (yrs)				
	30	25	20	15	10
Miles of Main Replaced Per Year		23	29	39	58
Number of Services Replaced Or Modified Per Year		2,500	3,125	4,167	6,250
Annual Capital Expenditures (\$000)		\$11,567	\$14,459	\$19,278	\$28,917





SECTION II DISTRIBUTION SYSTEM EVALUATION

BAY STATE GAS AND INDUSTRY HISTORY

Typical of most distribution companies with any significant history, the BSG system comprises a mix of piping material including: cast iron, wrought iron, non-cathodically protected bare steel, unprotected, or non-cathodically protected coated steel (UPCS), cathodically protected coated steel (CPCS) and plastic. The use of these different materials mirrors the history of the natural gas business. As technology, material sciences and the understanding of metal corrosion progressed, the industry chose the latest piping materials and protection methods for new construction and replacements. Each of the material and corrosion protection methods represented a step in the progression of best technology, and was intended to reduce the potential for pipe leaks and failures, and thereby improve system safety, reliability and maintenance costs. Chart 2-1 shows the approximate dates during which BSG installed pipes of these materials.

Plastic CPCS UPCS Bare Steel Wrought Iron 0 **Cast Iron** 0 1855 1905 1955 2005 Year of Installation

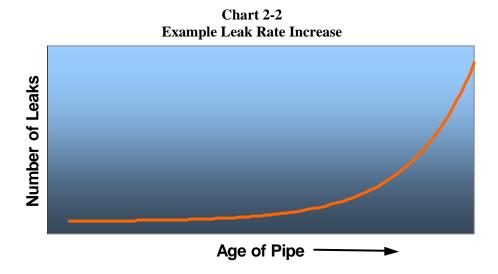
Chart 2-1 **BSG Piping Material History**

This progression of science and technology left most distribution companies with a mix of piping material in the ground, each with unique maintenance requirements and corrosion and degradation issues. As with any aging material or equipment, gas companies, pipeline safety experts and utility commissions have seen the need for the industry to monitor and replace older pipe in a manner that promoted continued safe operation and prudent expenditures.





Gas leaks on unprotected steel pipe are generally caused by material corrosion. Unprotected steel begins to corrode as soon as it is placed in the ground. Leaks are created when the corrosion degrades the pipe wall sufficiently to allow natural gas to escape. As corrosion thins the pipe wall, the number and likelihood of leaks increase. The rate of material corrosion is driven by a number of factors and can vary segment-to-segment. Generally, pipe corrosion data indicates the corrosion leak rate increases can be low or zero for many years eventually progressively increasing as the pipe continues to age (see Chart 2-2 below).



Throughout the natural gas industry, the policies and objectives that have driven the replacement of older pipes vary by company, region and state. In general, the objectives fall into two basic categories:

- 1. To complete replacement of certain types of pipe within a specified timeframe (e.g., a number of state commissions, including the Massachusetts Department of Telecommunications and Energy (DTE) have ordered the replacement of all cast iron pipe below a certain diameter).
- 2. To replace pipe segments as operational demands and pipe conditions dictate, based on one or more of the following:
 - a. Increased capacity requirements
 - b. Municipal improvements requiring replacement or relocation
 - c. Pipe failure or high number of historical leaks

⁹ Ibid 1.



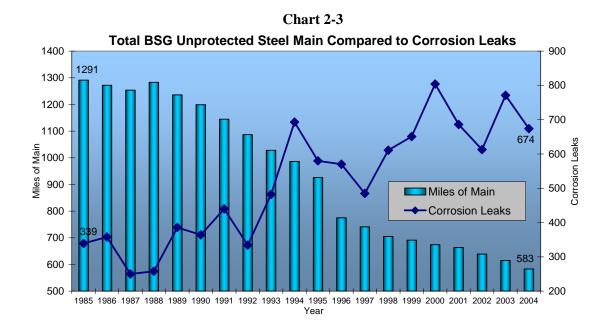




In addition to replacement practices, coated pipes with no cathodic protection, which are still in good condition and have an effective coating, are retrofitted with a cathodic protection system when cost justified. BSG staff indicated to Rudden that they had completed a system review and retrofitted all UPCS pipe in a condition suitable for cathodic protection. All remaining UPCS had sufficiently deteriorated coatings or other conditions that prevented an effective or cost-justified cathodic protection retrofit.

BSG's maintenance and replacement of older piping has been consistent with these general industry practices. Further, it is our opinion that BSG has, in place, a comprehensive leak monitoring program (BSG performs a physical leak survey on 100% of its system each year which exceeds both regulatory requirements and typical industry practice), and a responsive maintenance and construction team. This conclusion is based on our observations of BSG's operations, policies and procedures, as well as its better-than-average leak backlog/repair performance, as demonstrated by its operating results relative to other natural gas distribution companies as reported to the DOT.¹⁰

Notwithstanding the Company's solid track record, its recent unprotected steel corrosion leak history indicates that the number of leaks is progressing at rates higher-than-typical industry rates reported to the DOT (see Chart 2-3). Chart 2-3 (same as Chart 1-2) illustrates that despite the current unprotected steel replacement rate (as evidenced by the declining total miles of unprotected steel mains shown by the vertical bars), the trend in annual corrosion leaks (the solid line) continues to increase.



¹⁰ The data can be found on the web site of the DOT, Office of Pipeline Safety: http://ops.dot.gov/.





SECTION III LEAK FORECAST

DEVELOPMENT OF LEAK FORECAST

To forecast and compare alternative unprotected steel replacement scenarios, Rudden developed a forecast of the future expected leaks for the unprotected steel pipe in each of the three BSG divisions. This leak forecast was used in our analysis to either directly compute, or to otherwise support, four critical estimates:

- 1. The level of leak incidence that BSG is likely to experience in the future
- 2. The miles of pipe that would need to be replaced
- 3. The capital expenditures associated with the replacement pipe
- 4. The potential savings in maintenance and repair costs that might be experienced under alternative accelerated replacement schedules

METHODOLOGY & RESULTS

The Brockton Division of BSG (Brockton) accounts for, by far, the largest amount of unprotected steel main investment and greatest level of corrosion leak activity of BSG's three operating divisions. In addition, Brockton's distribution system is predominately high-pressure, which tends to promote higher leak rates. BSG has operated the Brockton system at a higher pressure than its other Divisions to meet the requirements for the existing customer usage. Table 3-1 which follows summarizes the miles of pipe and corrosion leak performance for each BSG division. Since the divisions each have a significant difference in the miles of installed unprotected steel mains, Rudden used a unitized leak rate of "leaks per mile" to compare the leak rates between the divisions.

¹¹ A pipeline operating at high pressure will allow more gas to escape than on a low-pressure pipeline with the same size corrosion hole. High-pressure leaks, because of the larger volume of gas escaping the pipeline, will typically be detected earlier than under similar conditions on a low-pressure pipeline. Colder winter weather, and the resultant higher customer natural gas usage, requires BSG to increase the distribution system operating pressure to maintain the gas pressure at the customer meters within acceptable limits. This relationship of cold winters, operating pressure and leaks can partially explain the saw tooth nature of the BSG historical leaks.





Table 3-1 Unprotected Steel Mains and Corrosion Leaks By Division for 2004

Division	Miles of Unprotected Steel Main	Number of Corrosion Leaks	Corrosion Leaks/Mile of Main
Brockton	368	509	1.38
Lawrence	75	90	1.20
Springfield	140	75	0.54
Total	583	674	1.16

In order to develop a leak forecast, Rudden conducted analysis on the historic corrosion leaks of each division using both time-series linear and non-linear regression analysis. Based on the relative distribution of the historic leak data and the expectation of a progressively increasing leak rate, Rudden analyzed the results of regression analysis using:

- 1. Linear time series
- 2. Exponential time-series
- 3. Second-order polynomial time series

The regression analysis was conducted for each division for historic leak data from 1985 to 2004. For each division, the results using a second-order polynomial time series yielded the best-fit results. The regression analysis yielded the following equations and coefficient of determination, or R^2 , which was the determining measure of how well the data fit the resultant equation.¹²

Brockton

Leaks/mile =
$$0.000040 * t^2 + 0.072719 * t + 0.058014$$

 $R^2 = 0.90$

Lawrence

Leaks/mile =
$$0.003964 * t^2 - 0.024937* t + 0.232932$$

 $R^2 = 0.86$

Springfield

Leaks/mile =
$$0.001267 * t^2 - 0.009139 * t + 0.205293$$

 $R^2 = 0.64$

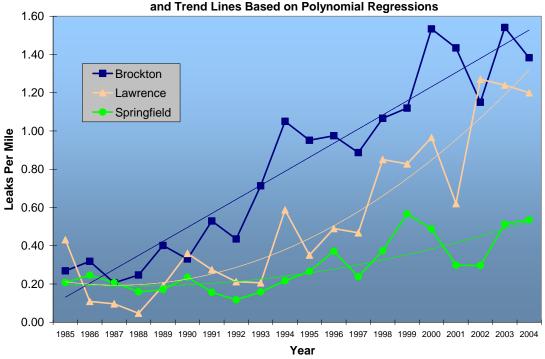
 $^{^{12}}$ R², or coefficient of determination, is a measure of how well a regression line approximates real data points; an R² of 1.0 indicates a perfect fit.





In these equations, "t" represents the time series representation for the year, with 1985 being year 1 and 2004 being year 20. These equations were used to forecast the division-level leaks on the unprotected steel for future years in the analysis. The historic leaks for each division and regression curves are shown in Chart 3-1

Chart 3-1 **Unprotected Steel Corrosion Leaks Per Mile by Division** and Trend Lines Based on Polynomial Regressions

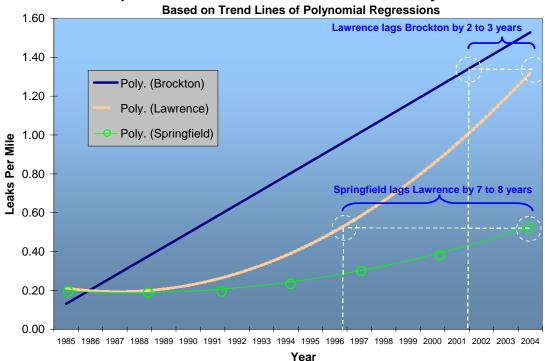


While the Brockton Division shows the higher current leak rate, the leak rate of each division is increasing significantly each year. Based on this historical data and general industry knowledge regarding the deterioration of unprotected steel, the leak rate in Lawrence is expected to soon meet and then surpass the current leak rates in Brockton. In addition, Springfield can be expected to follow the other two divisions with similarly progressively increasing leak rates. Using the best-fit trend lines for the leak rates in each division, Chart 3-2 indicates that the Lawrence leak rate lags behind the current Brockton leak rate by only 2 to 3 years and Springfield lags behind Lawrence by only about 7 to 8 years.





Chart 3-2 Unprotected Steel Corrosion Leaks Per Mile by Division



The forecasted leak rates were used to develop five unprotected steel replacement scenarios that were direct inputs to Rudden's Financial Model (Section IV of this report provides a discussion of the Financial Model). The five scenarios were based on full replacement of the BSG unprotected steel pipe over 10 to 30 years in 5-year increments. Each of the scenarios started with the amount of pipe as of December 31, 2004, then reduced this quantity by the amount necessary to complete the replacement of all unprotected steel within the scenario time period. The amount of pipe for each year was then multiplied by corresponding forecasted leak rate, from the equation above, to determine the number of leaks. Chart 3-3 which follows provides a graphical presentation of the results of the leak forecast for the 30-year (status quo) scenario including the impact of the pipe replacement rates. As shown in Chart 3-3, the 30-year replacement scenario is not forecasted to reduce the increasing number until 2012 and not return to 2004 levels until 2022.





Chart 3-3
Historical and Forecasted BSG Unprotected Steel Main
Replacement and Corrosion Leaks

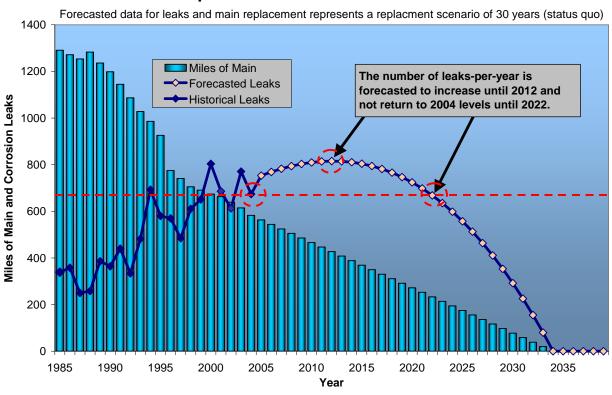






Chart 3-4 below provides a summary of the leak forecasts for each of the five scenarios.

Chart 3-4 Forecasted BSG Unprotected Steel Main Corrosion Leaks

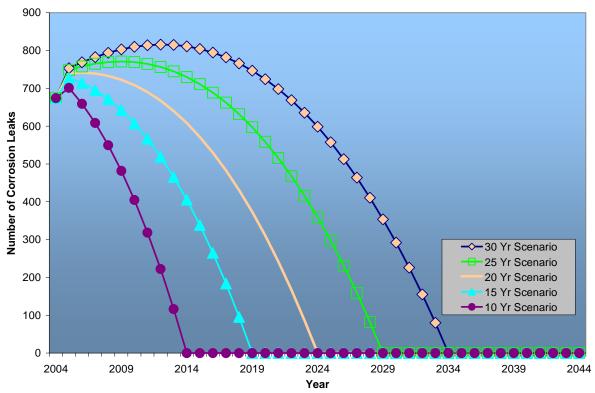
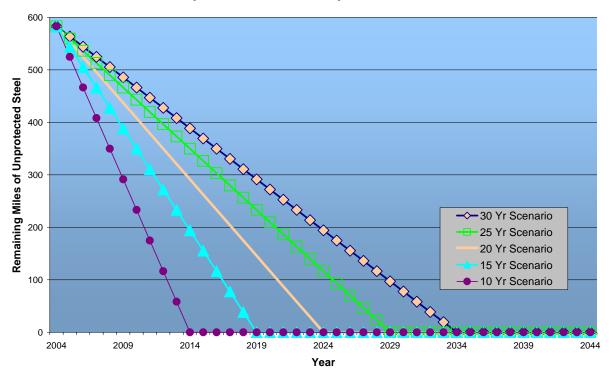






Chart 3-5 below provides a summary of the schedule of main replacements for each of the five scenarios.

Chart 3-5 **Unprotected Steel Replacement Rates**







SECTION IV REPLACEMENT OPTION ANALYSIS

OVERVIEW

Rudden developed a number of planning and policy options for replacing the existing unprotected steel mains and services. These options included replacement programs with different durations and different regulatory treatments for the recovery of the related program costs. Using the input developed from the historical mains and leak analyses discussed in the earlier sections of this report, the leak forecast, and a number of appropriate data assumptions 13 mutually agreed to by BSG and Rudden, we developed a Financial Analysis for a forecasted 40year period. The Financial Analysis examined the revenue requirements and cost impacts on both BSG and its customers under replacement schedules of 10 to 30 years (with 30 years representing an approximation of the current replacement schedule based on the approximated replacement rate over the last 5 years). The regulatory cost recovery scenarios analyzed for each of the replacement schedules included: annual rate cases, rate cases every three years, and recovery through a cost tracking mechanism with annual adjustments. The Financial Analysis yielded a net present value of the discounted cash flows (NPV), as of the beginning of 2005, associated with the carrying costs of the capital expenditures and the operating and maintenance costs for each scenario.

ANALYSIS

The distribution of natural gas to homes and businesses includes inherent risks due to the physical characteristics of natural gas. As a regulated utility, BSG must make economically- and operationally-prudent decisions. The continued safety of its customers and employees, as well as the continued safe and reliable operation of its natural gas delivery system, are paramount objectives for BSG in determining prudent decisions and actions. However, the continued deterioration of the unprotected steel components over time continues to challenge the ability of BSG to effectively manage the associated leaks and the risk of creating unsafe conditions. Given the historic and forecasted increasing corrosion leak rates of the unprotected steel components, Rudden does not consider that continuing at the current rate of replacement (i.e., the 30-year scenario) is a rational option, but has used that as the baseline for its financial analysis.

Based on the analysis and leak forecast described in the early sections of this report, we conclude that only options that accelerate the unprotected steel replacement provide reasonable alternatives for BSG. Rudden defined and analyzed replacement scenarios across a range of scenario lives that appeared to offer practical policy alternatives. The scenarios included a 30-year scenario that approximated the period of time required to replace all unprotected steel at BSG's approximate current replacement rate. We also defined additional scenarios down to the shortest period analyzed of 10-years. Rudden selected the 10-year scenario life as the estimated minimum time period that could allow reasonable coordination and accommodation of municipal and customer plans.



¹³ The primary assumptions are described in Appendix A.



The Financial Analysis projected a 40-year forecast of the "incremental changes" in specific cost components including: leak investigation and repair costs (O&M), capital expenditures, depreciation, income tax and property tax. While Rudden considered shorter analysis periods, 40 years was selected to substantially exceed each of the replacement scenarios considered. These "incremental changes" were calculated from 2004 costs based on the projected value of the cost component in each study year, less the value of the cost component at end-of-year 2004. For example, the investigation and repair costs for corrosion leaks in 2004 was \$2,819,000 for the 30-year scenario. The costs in 2005 were estimated at \$3,229,000, which accounted for the forecasted increase in the number of leaks and inflation adjustments. Only the incremental increase from 2004 to 2005, or \$410,000, was used in this analysis. At the time of this analysis, BSG was contemplating a rate filing for an adjustment to base rates, with a test year of 2004. Rudden chose to use the incremental change from the end-of-year 2004 since it was assumed that all costs prior to January 2005 would be included in base rates.

Since BSG does not ordinarily forecast individual cost components 40 years into the future, Rudden and BSG agreed to forecast future leak investigation and repair costs proportionately to the leak forecast for the unprotected steel pipe remaining in the ground. Rudden assumed that all replacement pipe has a zero leak rate for the life of the study. This assumption serves to provide a conservatively high estimate of the O&M savings associated with the replacement of the unprotected steel pipe.

The annual cash flows resulting from the incremental changes in each cost component was then discounted to the beginning-of-year 2005 dollars using net present value methods. Rudden constructed the Financial Analysis to calculate summary results for comparative purposes. Due principally to the long 40-year life of the Financial Analysis, Rudden expects that the actual future costs would vary from the results of the Financial Analysis, but, likely not with a magnitude sufficient to materially change the relative results of the scenarios, our conclusions or recommendations.¹⁴

RESULTS

As shown in Chart 4-1, each scenario will ultimately result in an incremental savings (a negative value would represent an incremental savings) in the annual cost of O&M relative to the levels experienced in 2004. However, Chart 4-1 also shows that only the shortest scenario of 10 years, offers the prospect of any near-term O&M savings.

¹⁴ Any long-term forecast is susceptible to potentially significant variance in the actual vs. forecasted results due to the difficulties associated with the forecasting the inputs for the analysis over such lengthy periods.





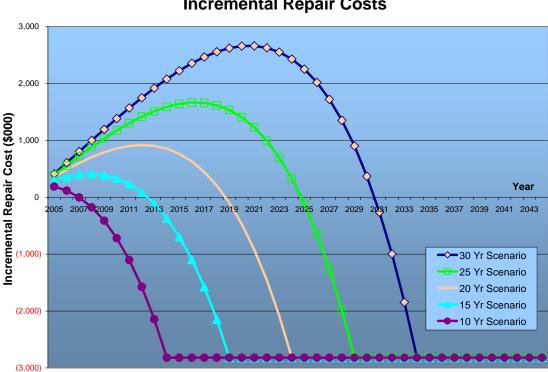


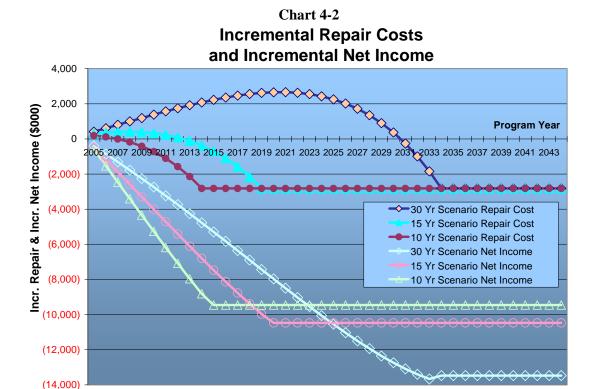
Chart 4-1
Incremental Repair Costs

Chart 4-2 shows the forecasted incremental investigation and repair costs and the corresponding incremental net income for the 10-year and 30-year replacement programs, assuming the Company's present rates remained in effect (i.e., there was neither a general rate increase or a tracker mechanism that would recover the incremental costs). The incremental net income includes the incremental O&M, depreciation, ¹⁵ income taxes and property taxes. For each year and for each of the five scenarios analyzed, the net income started and stayed negative throughout the life of the study. This continuous negative income held for even the shortest scenarios, which offered the greatest and earliest O&M savings. This could be expected due to the minimal relative O&M savings compared to the large impact of the expense-related carrying charges associated with the capital replacements, such as depreciation and property taxes. In other words, without rate relief, the Company's need to replace mains and services would result in significant earnings losses, even after the savings in operating costs associated with the reduction in leaks are considered.

¹⁵ The depreciation expense included in this analysis only addresses depreciation associated with the replacement pipe. Rudden has assumed that the existing base rates include the depreciation expense on the bare steel. Rudden has assumed that any replacement program approved would be subject to the depreciation rates approved in the Company's rate cases.







Clearly, these earnings losses would not be acceptable or sustainable. To examine the level of rates and revenue that would be required to keep the Company whole, we calculated the annual incremental revenue requirement for each of the 40-years of the analysis, for each scenario, based on:

- Expenses associated with O&M, depreciation, income taxes and property taxes
- Return on capital investments resulting from retirement and replacement related to the unprotected steel main replacement

Rudden then extended calculations for the revenue requirement to three plausible regulatory treatment methods that would recover the incremental costs and earn a return on the investments attributable to an accelerated unprotected steel replacement program. Included in these regulatory recovery methods was a Program Tracker. The Program Tracker was designed to address the expenses and investments of the replacement program through a charge or rider separate from base rates. Rudden designed the Program Tracker to adjust charges on an annual basis to recover portions of the annual revenue requirement attributable to the BSG unprotected steel replacements. The four regulatory programs included:





- **Annual Rate Case** This regulatory program assumes that rate cases would be filed annually for the duration of each replacement scenario. The rate cases would adjust revenue to provide a return on the incremental capital investment and recovery of all incremental repair expenses, depreciation, property taxes and income taxes. Rates would be set based on the costs and investment levels for the year prior to the filing.
- Rate Cases Every 3 Years This regulatory program assumes that rate cases would be filed every three years for the duration of each replacement scenario. The rates cases would adjust revenue to provide a return on the incremental capital investment and recovery of all incremental repair expenses, depreciation, property taxes and income taxes. Rates would be set based on the costs and investment levels for the year prior to the filing.
- **Program Tracker** This regulatory program assumes that revenue adjustments would be made each year to provide a return on the capital investment and recovery of the depreciation and property tax associated with the unprotected steel replacements. These annual adjustments would be independent of any base rate proceeding in which the Company might be involved; made based on a pre-approved methodology; and would not require a full rate proceeding.

The two rate case programs each assume a one-year lag between the test period and the period in which the test period costs would be recovered (e.g., costs for test period ending December 31, 2005 are recovered beginning in January 1, 2007). The Program Tracker method assumes costs and investments are recovered in the year following the year they are incurred (e.g., costs for test period ending December 31, 2005 are recovered beginning in January 1, 2006). The Program Tracker method includes a transition to a schedule of rate cases every three years beginning in the year following the end of unprotected steel replacement program (e.g., for the 10-year scenario, the program tracker ends in the tenth year; in the eleventh year, revenue recovery is adjusted in a rate case, and rate case adjustments follow every 3 years thereafter). This transition from a Program Tracker to regular rate cases after completing replacements captures the O&M savings and prevents an over-recovery of the BSG revenue requirement from the Program Tracker.

Table 4-1 which follows presents the results of each of these regulatory recovery methods. The results are presented as a net present value (NPV) of the stream of annual values.





Table 4-1 Summary of Scenario Costs

	BSG Unprotected Steel Analysis Results (\$000)				\$000)
	30 yr	25 yr	20 yr	15 yr	10 yr
NPV of Cumulative Revenue Requirement	\$145,305	\$160,297	\$176,529	\$196,133	\$220,070
Annual Rate Case					
NPV of Revenue Recovery from Annual Rate Cases	\$127,218	\$140,832	\$155,589	\$173,303	\$194,842
NPV of Revenue Shortfall for BSG	\$18,087	\$19,465	\$20,940	\$22,830	\$25,228
Rate Case Every Three Years					
NPV of Revenue Recovery from Rate Cases Every 3 Yrs	\$116,136	\$128,594	\$142,587	\$158,603	\$178,567
NPV of Revenue Shortfall for BSG	\$29,169	\$31,703	\$33,942	\$37,530	\$41,503
Program Tracker - Capital, Depr. & Prop. Tax					
NPV of Revenue Recovery from Tracker, Depr & Prop Tax	\$132,430	\$150,454	\$170,075	\$192,478	\$217,453
NPV of Revenue Shortfall for BSG	\$12,874	\$9,843	\$6,454	\$3,655	\$2,616

As the data shows, the revenue requirement increases progressively as the unprotected steel replacement period is shortened. Table 4-1 also presents a calculation of the revenue shortfall for BSG under each of the scenarios. The results indicate BSG can expect a significant shortfall from their revenue requirement with each scenario and each regulatory recovery method. For the programs that contemplate cost recovery through rate cases, the shortfall from the revenue requirement is due to the ordinary lag in regulatory recovery, resulting from the use of historic test years in filings and subsequent lag between the occurrence of the costs used in the filing and the resultant rate relief. For the recovery through the Program Tracker, the revenue shortfall is due to the fact that the Program Tracker is not designed to recover all expenses in combination with the ordinary lag in regulatory recovery, resulting from both the Program Tracker and the subsequent rate cases relying on historic-year data.¹⁷

By subtracting the 30-year values in Table 4-1 from their equivalent values in the other scenario columns, an approximation of the added revenue requirement over and above the status quo can be calculated. Table 4-2 presents the results of the analysis compared to the status quo represented by the 30-year scenario. As seen in Table 4-2, the added revenue requirement for any of the accelerated replacement schedules is substantial.

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¹⁶ The revenue shortfall is a forecast of the portion of the BSG revenue requirement that is not recovered through the rate cases or Program Trackers.

¹⁷ The revenue requirement and the revenue shortfall calculations do not include Construction Work in Progress (CWIP). In addition, costs are calculated at year-end, so the intra-year lag in cost recovery is not included.

Table 4-2 Scenario Costs Compare to Status Quo

		Scenario Incremental Change Compared to 30 Year Scenario		
	25 yr	20 yr	15 yr	10 yr
NPV of Cumulative Revenue Requirement	\$14,992	\$31,224	\$50,829	\$74,765
Annual Rate Case				
NPV of Revenue Recovery from Annual Rate Cases	\$13,614	\$28,371	\$46,085	\$67,624
Rate Case Every Three Years				
NPV of Revenue Recovery from Rate Cases Every 3 Yrs	\$12,458	\$26,452	\$42,467	\$62,431
Program Tracker - Capital, Depr. & Prop. Tax				
NPV of Revenue Recovery from Tracker, Depr & Prop Tax	\$18,024	\$37,644	\$60,048	\$85,023

Sensitivity Analysis

Rudden completed a number of additional variations on the analysis described above to evaluate the sensitivity to the assumptions used in the analysis. The variations include:

- a. **Return on Capital** The base assumption was 9.5% (after tax); 9.75% and 9.25% were also analyzed.
- b. Capital Investment The base assumption was formulated with all BSG unprotected steel replaced over a specific scenario length; variations were run to the capital investment for 75% and 125% of the base costs.
- c. Leak Forecast Variation were run on the division level leak forecasts for 50% of the annual increase in leaks and 125% of the annual increase in leaks relative to the base case.

Appendix B presents a summary of the results of these sensitivity analyses. Each of the scenarios analyzed in the sensitivity analysis provided similar results to the base case. None of these changes to the assumptions proved to have a material impact on the conclusions regarding the outcome or the relationship between the scenarios for different replacement durations.

In each of the scenarios, Rudden assumed that the replacement programs replaced a fixed number of miles of BSG's unprotected steel main and services each year. Due to the assumed inflation on the cost of replacement, each year the dollars required for the replacement of the fixed number of miles increases. However, as a plausible alternative, fixing the dollars spent each year may offer benefits over a program that replaces a fixed amount of main. Fixing the dollars each year assumes more miles of main are replaced in the early years but, each year, the miles replaced decreases. Table 4-3 which follows shows the annual stream of capital investments for the 10-year scenario rises from a first-year cost of \$28,917,000 to a tenth-year cost of \$38,731,000. The equivalent annual fixed dollar investment that would provide the equivalent replacements over the ten-year period is \$32,811,000.





Table 4-3 10-Year Scenario - Capital Replacements (\$000)

	Captial Replacements with a Fixed Mileage	Captial Replacements with a Fixed Dollar Amount
1	\$28,917	\$32,811
2	\$29,871	\$32,811
3	\$30,857	\$32,811
4	\$31,875	\$32,811
5	\$32,927	\$32,811
6	\$34,014	\$32,811
7	\$35,136	\$32,811
8	\$36,296	\$32,811
9	\$37,494	\$32,811
10	\$38,731	\$32,811

Table 4-4 below shows the annual stream of capital investments for the 15-year scenario rises from a first-year cost of \$19,278,000 to a fifteenth-year cost of \$30,372,000. The equivalent annual fixed dollar investment that would provide the equivalent replacements over the 15-year period is \$23,150,000.

Table 4-4
15-Year Scenario - Capital Replacements (\$000)

	Captial Replacements with a Fixed Mileage	Captial Replacements with a Fixed Dollar Amount
1	\$19,278	\$23,150
2	\$19,914	\$23,150
3	\$20,571	\$23,150
4	\$21,250	\$23,150
5	\$21,952	\$23,150
6	\$22,676	\$23,150
7	\$23,424	\$23,150
8	\$24,197	\$23,150
9	\$24,996	\$23,150
10	\$25,821	\$23,150
11	\$26,673	\$23,150
12	\$27,553	\$23,150
13	\$28,462	\$23,150
14	\$29,401	\$23,150
15	\$30,372	\$23,150





SECTION V CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

Through the analysis presented in this report, Rudden has concluded that BSG should increase the rate of replacement of their remaining unprotected steel mains and services. Based on the interviews and material reviewed by Rudden, as well as our general industry knowledge, BSG appears to have followed a reasonable schedule of replacement for roughly the last two decades, and has monitored and maintained the existing system in a manner consistent with prudent utility practices. Rudden has based these conclusions on a review of BSG and industry Leak Detection, Leak Management Performance and unprotected steel Replacement Rates.

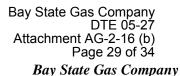
Leak Detection – A comprehensive and effective leak detection process provides the cornerstone of any pipeline safety and leak management program. A quality leak detection program provides the information to allow utilities to identify and then repair leaks. DOT and the DTE require gas distribution companies to perform regular system surveys to identify and categorize the severity of all leaks. BSG has consistently exceeded the DOT and DTE leak survey requirements by performing its leak survey on 100% of its distribution system each year. The DOT (Part 192.723) requires operators to conduct leakage surveys in business districts at intervals not exceeding fifteen months but at least once per calendar year. In areas other than business districts, DOT requires leakage surveys at intervals not exceeding five years unless there are non-cathodically protected pipes, in which case they must be surveyed at intervals not exceeding three years. The DTE (220 CMR 101.06.21) requires business districts to be surveyed once per year, and in areas other than business districts, once every consecutive twenty-four month period.

Leak Management Performance – An effective measure of how well a company performs in managing its leak backlog is the leak backlog/repair ratio. The BSG performance in this measure has been better than average and ranking on average since 1993, well within the first quartile based industry data reported on the DOT web site. However, in 2003, the company experienced a large increase in corrosion leaks (771 leaks in 2003 compared to 613 leaks in 2002 or a 26% increase in a single year). This large increase strained the BSG resources and resulted in an increase in the leak backlog in 2003.

Unprotected Steel Replacement – Non-cathodically protected bare steel mains and services and non-cathodically protected coated steel mains and services have presented known corrosion issues since their installation was ceased in the 50's and 70's, respectively. Many gas distribution companies, including BSG, began replacing their unprotected steel pipes in the 80's. Based on unprotected steel replacement rates reported on the DOT web site, BSG's replacement rate has been comparable to other companies with unprotected steel.

With the last bare steel installed in approximately 1955, BSG's current 30-year replacement schedule implicitly assumes a useful life for these materials of up to 80 years (or 65 years for non-cathodically protected coated steel







which was last installed in approximately 1970). Given the effects of corrosion on these materials, the recent leak history of BSG and the safety issues associated with natural gas pipe integrity, it is our opinion that the useful life of most, if not all, unprotected steel mains and services is significantly less than the implicit 65- to 80-year life. At the current replacement rates, and after discussion with both BSG staff and Heath consultants, it is likely that the increasing number of leak repairs will soon overtake BSG's ability to effectively manage the risks associated with current replacement practices. The large increase in the number of leaks in 2003 was accompanied by a large increase in the leak backlog (i.e., those leaks that were still not repaired by year end). This suggests that the rate of replacement needs to be accelerated if the backlog ratio is to be brought under control, and the longer-term objective of replacing unprotected steel pipe is to be achieved anytime soon. Rudden expects the year-to-year leaks to continue to fluctuate in the future but still show a continually increasing, long-term trend based on our leak forecast described in this report.

Based on our analysis and leak forecast, Rudden recommends that BSG accelerate its current replacement schedule and replace the remaining unprotected steel in as short of time practicable given the constraints of rate impacts and construction coordination with the municipal agencies. Rudden believes the shortest scenarios analyzed, 10 to 15 years, offers reasonable approximation of a practicable, minimum replacement schedule.





APPENDIX A FINANCIAL MODEL ASSUMPTIONS

The tables below provides a summary of the base assumptions for the analysis.

Assumptions				
1. Scenarios are based on unprotected steel replacer	ment of:			
	Brockton	Lawrence	Springfield	
yrs	miles/yr	miles/yr	miles/yr	
30	12.3	2.5	4.7	Status Quo
25	14.7	3.0	5.6	
20	18.4	3.8	7.0	
15	24.5	5.0	9.3	
10	36.8	7.5	14.0	

- The costs are incremental costs from 2004, the last year prior to replacement program initiation in 2005. It is assumed that historic expense levels and investments prior to 2005 will be recovered in base
- 3. All present value (PV) calculations are discounted to 2005, the first year of the program
- 3. Dollars are shown in units of \$000 unless stated otherwise
- Annual O&M for main & service leak repair for the remaining BS/UPCS is increased proportional to the division leak forecast for mains
- 5. Leak rate for all replacements is conservatively assumed to be zero
- 6. Costs conservatively assume O&M benefit from replaced pipe starts January 1 or each year
- 7. All replaced pipe is assumed to cost zero dollars for removal
- 8. The cost of rate cases for BSG, DTE and interveners is not included
- 9. The book life of pipe used for replacements is greater than the duration of each scenario
- 10. Each scenario is calculated over a 40 yr period with no additional end-effects
- 11. The possible regulatory treatment of the BSG revenue requirement are modeled using three methods:
 - i. Annual rate cases with full recovery of costs and return on investment
 - ii. Rate cases every three years with full recovery of costs and return on investment
 - iii. Program Tracker which provides annual recovery of depreciation, taxes and return on capital
- 12. The two rate case methods each assume a one-year lag for rate recovery
- 13. The Program Tracker method assumes costs and investments are recovered in the year following the year they are incurred.
- 13. The Program Tracker method transitions to a schedule of rate cases every three years beginning in the year following the end of bare steel replacement program (e.g. for the 10-year scenario, the program tracker ends in year ten; in year eleven revenue recovery is adjusted in a rate case, rate case adjustments follow every 3-years thereafter).





Bay State Gas Company

Distribution Infrastructure Replacement

							Source
Input	Total	Brockton	Lawrence	Springfield	Units	Source	Year
Weighted Average Cost of Capital - After Tax	9.5%				%	BSG & RJR	2003
Income Tax Rate (combined Fed & State)	39.225%				%	BSG	2004
Property Tax Rate calculated on Gross Plant	3.5%				%	BSG	2004
Depreciation - Common Rate	1.97%				%	BSG	2004
Inflation	3.3%				%	BSG	2003
Main Replacement Cost	\$72				\$/ft	BSG	2004
Overhead for O&M Labor	103.3%				% of Labor	BSG	2003
Overhead for O&M Material	22.3%				% of Mat'l	BSG	2003
Miles of Existing Installed Unprotected Steel Main	583	368	75	140	miles	BSG	2004
Value of Program Replacements Mains	\$221,633	\$139,899	\$28,512	\$53,222	\$000	BSG	2004
Number of Services To Be Replaced	29,520					BSG	2004
Number of Plastic Services To Be Tied-Over	7,380					BSG	2004
Number of Meters & Regulators To Be Moved	25,600					BSG	2004
Services Per Mile of Main		39	56	58	svc/mile	BSG	2003
Value of Program Services Replacements	\$58,300	\$31,419	\$9,102	\$17,779	\$000	BSG	2004
Total Value of Program Mains & Services	\$279,933	\$171,317	\$37,614	\$71,002	\$000	BSG	2004
Cost of Leak Investigation and Leak Repair	\$2,819	\$1,678	\$487	\$654	\$000	BSG	2004





APPENDIX B SENSITIVITY ANALYSIS RESULTS

Return on Capital plus 0.25% to 9.75%	BSG	Uprotected	Steel Analys	is Results (\$	(000
	30 yr	25 yr	20 yr	15 yr	10 yr
NPV of Cumulative Revenue Requirement	\$142,194	\$157,176	\$173,586	\$193,523	\$218,014
Annual Rate Case					
NPV of Revenue Recovery from Annual Rate Cases	\$124,239	\$137,803	\$152,673	\$170,634	\$192,611
NPV of Revenue Shortfall for BSG	\$17,955	\$19,373	\$20,912	\$22,889	\$25,403
Rate Case Every Three Years					
NPV of Revenue Recovery from Rate Cases Every 3 Yrs	\$113,222	\$125,609	\$139,664	\$155,875	\$176,187
NPV of Revenue Shortfall for BSG	\$28,971	\$31,566	\$33,922	\$37,648	\$41,827
Program Tracker - Capital, Depr. & Prop. Tax					
NPV of Revenue Recovery from Tracker, Depr & Prop Tax	\$129,581	\$147,483	\$167,179	\$189,854	\$215,361
NPV of Revenue Shortfall for BSG	\$12,613	\$9,692	\$6,407	\$3,669	\$2,653

Return on Capital minus 0.25% to 9.25%	BSG	Uprotected	Steel Analys	79,551 \$198,802 58,586 \$176,033 20,966 \$22,769 45,594 \$161,396 33,957 \$37,406 73,049 \$195,160	(\$000)	
-	30 yr	25 yr	20 yr	15 yr	10 yr	
NPV of Cumulative Revenue Requirement	\$148,522	\$163,515	\$179,551	\$198,802	\$222,163	
Annual Rate Case						
NPV of Revenue Recovery from Annual Rate Cases	\$130,301	\$143,956	\$158,586	\$176,033	\$197,115	
NPV of Revenue Shortfall for BSG	\$18,221	\$19,559	\$20,966	\$22,769	\$25,048	
Rate Case Every Three Years						
NPV of Revenue Recovery from Rate Cases Every 3 Yrs	\$119,153	\$131,676	\$145,594	\$161,396	\$180,992	
NPV of Revenue Shortfall for BSG	\$29,369	\$31,839	\$33,957	\$37,406	\$41,171	
Program Tracker - Capital, Depr. & Prop. Tax						
NPV of Revenue Recovery from Tracker, Depr & Prop Tax	\$135,378	\$153,518	\$173,049	\$195,160	\$219,583	
NPV of Revenue Shortfall for BSG	\$13,144	\$9,997	\$6,503	\$3,641	\$2,580	





Bay State Gas Company

Distribution Infrastructure Replacement

Capital Expenditures plus 25%	BSG	Uprotected	Steel Analys	\$246,445 \$246,445 \$217,673 \$28,772 \$199,189 \$47,256 \$241,660 \$4,784	6000)
· · · ·	30 yr	25 yr	20 yr	15 yr	10 yr
NPV of Cumulative Revenue Requirement	\$179,479	\$199,303	\$220,739	\$246,445	\$277,608
Annual Rate Case					
NPV of Revenue Recovery from Annual Rate Cases	\$157,206	\$175,127	\$194,530	\$217,673	\$245,633
NPV of Revenue Shortfall for BSG	\$22,273	\$24,176	\$26,209	\$28,772	\$31,975
Rate Case Every Three Years					
NPV of Revenue Recovery from Rate Cases Every 3 Yrs	\$143,486	\$159,887	\$178,269	\$199,189	\$225,092
NPV of Revenue Shortfall for BSG	\$35,993	\$39,417	\$42,470	\$47,256	\$52,516
Program Tracker - Capital, Depr. & Prop. Tax					
NPV of Revenue Recovery from Tracker, Depr & Prop Tax	\$165,705	\$188,412	\$213,217	\$241,660	\$273,564
NPV of Revenue Shortfall for BSG	\$13,774	\$10,892	\$7,523	\$4,784	\$4,044

Capital Expenditures minus 25%	Capital Expenditures minus 25% BSG Uprotected Steel Analysis Results (
	30 yr	25 yr	20 yr	15 yr	10 yr
NPV of Cumulative Revenue Requirement	\$111,130	\$121,290	\$132,319	\$145,822	\$162,532
Annual Rate Case					
NPV of Revenue Recovery from Annual Rate Cases	\$97,230	\$106,536	\$116,649	\$128,933	\$144,051
NPV of Revenue Shortfall for BSG	\$13,900	\$14,754	\$15,670	\$16,889	\$18,481
Rate Case Every Three Years					
NPV of Revenue Recovery from Rate Cases Every 3 Yrs	\$88,786	\$97,302	\$106,905	\$118,017	\$132,042
NPV of Revenue Shortfall for BSG	\$22,345	\$23,989	\$25,413	\$27,805	\$30,490
Program Tracker - Capital, Depr. & Prop. Tax					
NPV of Revenue Recovery from Tracker, Depr & Prop Tax	\$99,156	\$112,497	\$126,933	\$143,296	\$161,343
NPV of Revenue Shortfall for BSG	\$11,974	\$8,793	\$5,386	\$2,526	\$1,189





Bay State Gas Company

Distribution Infrastructure Replacement

Annual Leak Increase plus 25%	BSG	Uprotected	Steel Analys	7 \$174,200 \$23,009 7 \$159,435 \$37,774	(000
·	30 yr	25 yr	20 yr	15 yr	10 yr
NPV of Cumulative Revenue Requirement	\$148,248	\$162,591	\$178,192	\$197,209	\$220,637
Annual Rate Case					
NPV of Revenue Recovery from Annual Rate Cases	\$129,673	\$142,745	\$156,977	\$174,200	\$195,315
NPV of Revenue Shortfall for BSG	\$18,575	\$19,846	\$21,216	\$23,009	\$25,322
Rate Case Every Three Years					
NPV of Revenue Recovery from Rate Cases Every 3 Yrs	\$118,393	\$130,356	\$143,857	\$159,435	\$179,011
NPV of Revenue Shortfall for BSG	\$29,855	\$32,235	\$34,335	\$37,774	\$41,626
Program Tracker - Capital, Depr. & Prop. Tax					
NPV of Revenue Recovery from Tracker, Depr & Prop Tax	\$132,450	\$150,480	\$170,107	\$192,518	\$217,504
NPV of Revenue Shortfall for BSG	\$15,798	\$12,111	\$8,085	\$4,691	\$3,133

Annual Leak Increase Minus 25%	BSG Uprotected Steel Analysis Results (\$000)				
	30 yr	25 yr	20 yr	15 yr	10 yr
NPV of Cumulative Revenue Requirement	\$139,418	\$155,708	\$173,203	\$193,981	\$218,936
Annual Rate Case					
NPV of Revenue Recovery from Annual Rate Cases	\$122,309	\$137,005	\$152,815	\$171,508	\$193,897
NPV of Revenue Shortfall for BSG	\$17,109	\$18,704	\$20,387	\$22,473	\$25,039
Rate Case Every Three Years					
NPV of Revenue Recovery from Rate Cases Every 3 Yrs	\$111,622	\$125,071	\$140,048	\$156,937	\$177,678
NPV of Revenue Shortfall for BSG	\$27,796	\$30,638	\$33,155	\$37,044	\$41,258
Program Tracker - Capital, Depr. & Prop. Tax					
NPV of Revenue Recovery from Tracker, Depr & Prop Tax	\$132,390	\$150,403	\$170,011	\$192,398	\$217,353
NPV of Revenue Shortfall for BSG	\$7,028	\$5,305	\$3,192	\$1,584	\$1,583



COMMONWEALTH OF MASSACHUSETTS DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL D. T. E. 05-27

Date: May 26, 2005

Responsible: Danny G. Cote, General Manager

AG-2-34 Create a bar graph with the years 1990 to 2005 along x-axis and

Company costs of bare steel main replacement per year along the y-axis. Include all work papers, calculations and assumptions used to calculate the costs of bare steel main replacements per year.

Response: Attachment AG-2-34 is a bar graph with the years 1994 to 2005 along x-

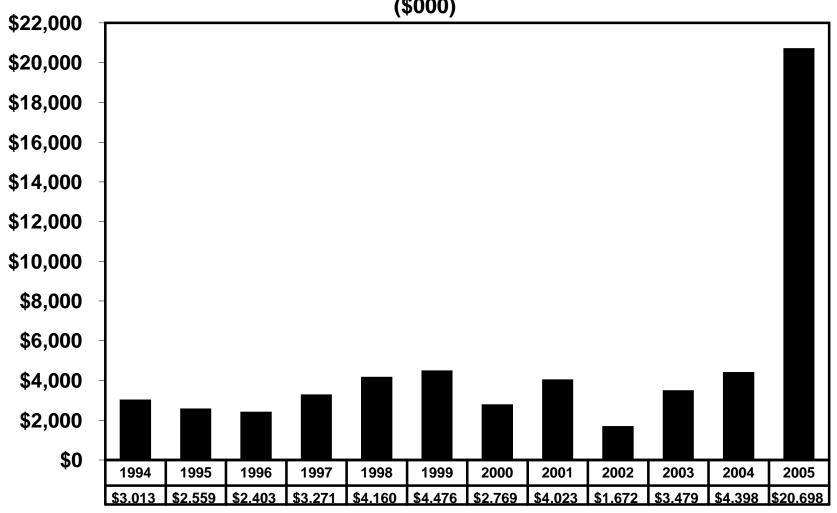
axis and Company costs of bare steel main replacement per year along the y-axis. The source of the historical data for this graph comes directly from the Company's Work Order Management System. Data for 2005 is

based on the Company's 2005 construction budget.

Data is not readily available for 1990-1993.

There are no other work papers, calculations and assumptions used to calculate the costs of bare steel main replacements per year.

Massachusetts All Locations Bare Steel Main Replacement: 1994-2005 (\$000)



COMMONWEALTH OF MASSACHUSETTS DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL D. T. E. 05-27

Date: May 26, 2005

Responsible: Danny G. Cote, General Manager

AG-2-35 Create bar graphs with the years 1990 to 2005 along x-axis and the costs

of bare steel main replacement per year along the y-axis for the

Springfield, Lawrence and Brockton service territories. Include all work papers, calculations and assumptions used to calculate the costs of bare

steel main replacements per year.

Response: Attached are bar graphs with the years 1994 to 2005 along x-axis and

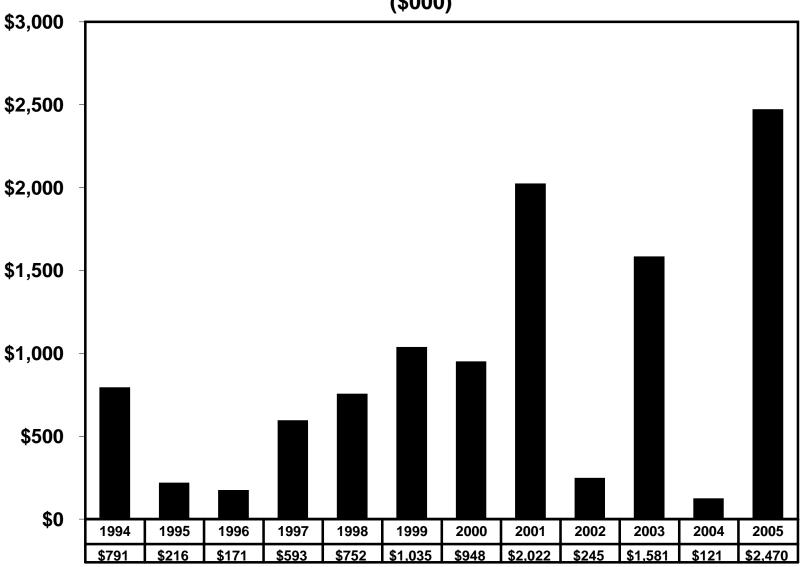
Company costs of bare steel main replacement per year along the y-axis. Attachments AG-2-35(a), AG-2-35(b) and AG-2-35(c) represent data for the Springfield, Lawrence and Brockton service territories, respectively. The source of the historical data for these graphs comes directly from the Company's Work Order Management System. Data for 2005 is based on

the Company's 2005 construction budget.

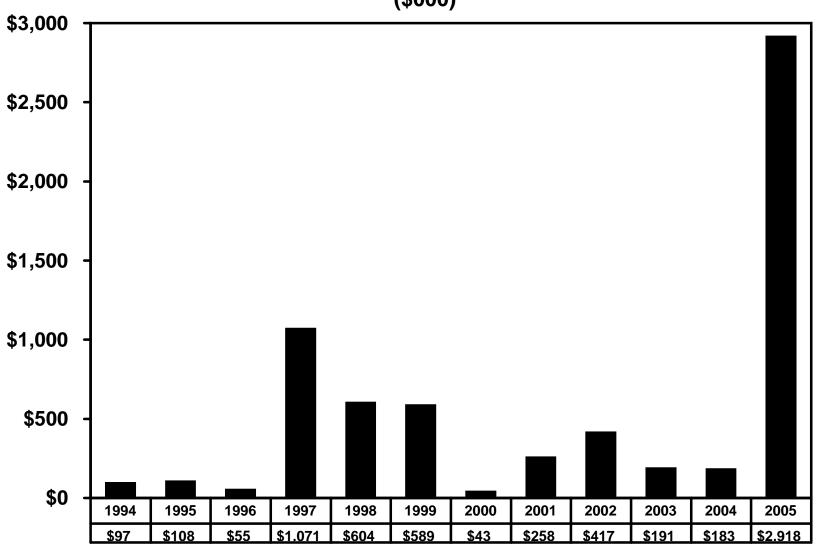
Data is not readily available for 1990-1993.

There are no other work papers, calculations and assumptions used to calculate the costs of bare steel main replacements per year.

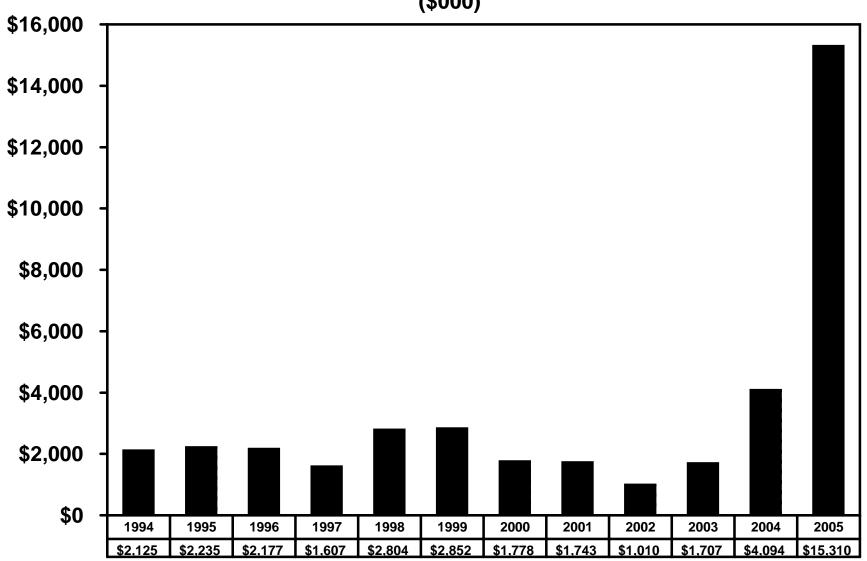
Springfield
Bare Steel Main Replacement: 1994-2005
(\$000)



Lawrence
Bare Steel Main Replacement: 1994-2005
(\$000)



Brockton
Bare Steel Main Replacement: 1994-2005
(\$000)



COMMONWEALTH OF MASSACHUSETTS DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL D. T. E. 05-27

Date: May 26, 2005

Responsible: Danny G. Cote, General Manager

AG-2-36 Create a bar graph with the years 1990 to 2005 along x-axis and

Company costs of bare steel services replacement per year along the yaxis. Include all work papers, calculations and assumptions used to calculate the costs of bare steel service replacements per year.

Response: Attachment AG-2-36 is a bar graph with the years 1994 to 2005 along x-

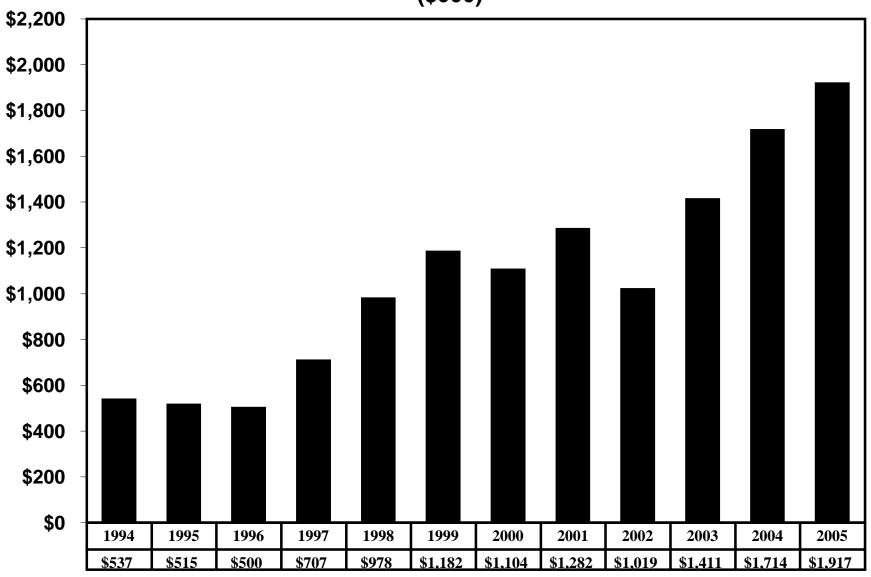
axis and Company costs of bare steel service replacement per year along the y-axis. The source of the historical data for this graph comes directly from the Company's Work Order Management System. Data for 2005 is

based on the Company's 2005 construction budget.

Data is not readily available for 1990-1993.

There are no work papers, calculations and assumptions used to calculate the costs of bare steel service replacements per year.

Massachusetts All Locations Bare Steel Services: 1994-2005 (\$000)



COMMONWEALTH OF MASSACHUSETTS DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL D. T. E. 05-27

Date: May 26, 2005

Responsible: Danny G. Cote, General Manager

AG-2-37

Create bar graphs with the years 1990 to 2005 along x-axis and the costs of bare steel services replacement per year along the y-axis for the Company's service territories in the cities of Springfield, Lawrence and Brockton. Include all work papers, calculations and assumptions used to calculate the costs of bare steel services per year for each of the cities.

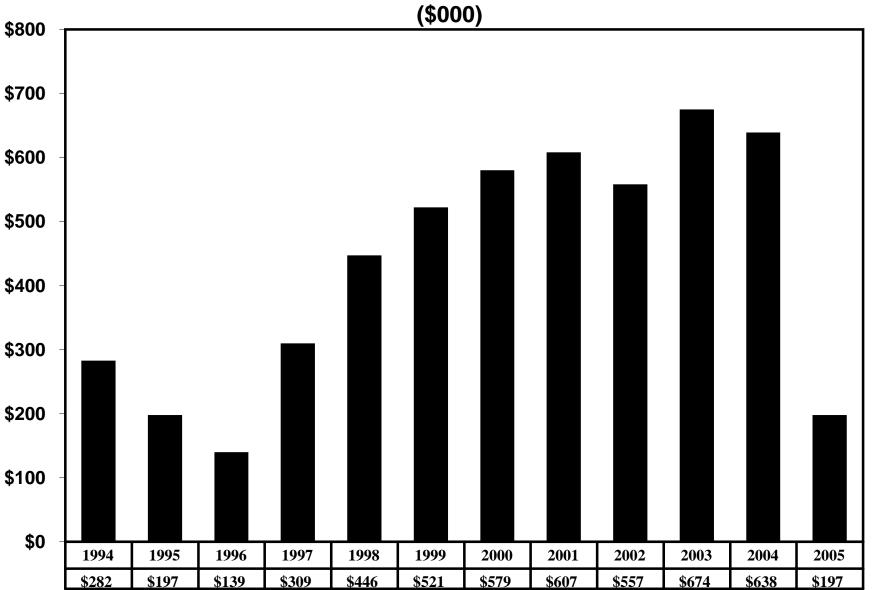
Response:

Attached are bar graphs with the years 1994 to 2005 along x-axis and Company costs of bare steel service replacement per year along the y-axis. Attachments AG-2-37(a), AG-2-37(b) and AG-2-37(c) represent data for the Springfield, Lawrence and Brockton service territories, respectively. The source of the historical data for this graph comes directly from the Company's Work Order Management System. Data for 2005 is based on the Company's 2005 construction budget.

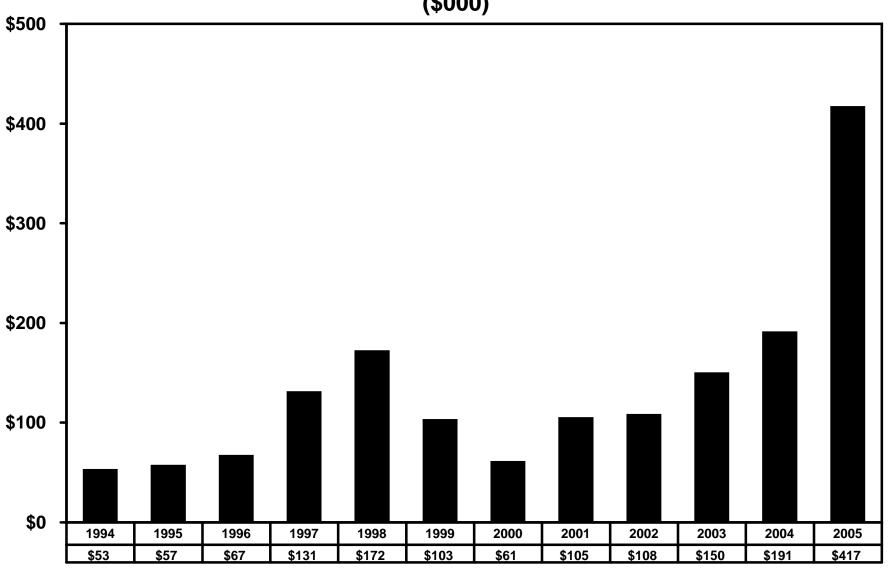
Data is not readily available for 1990-1993.

There are no work papers, calculations and assumptions used to calculate the costs of bare steel service replacements per year.

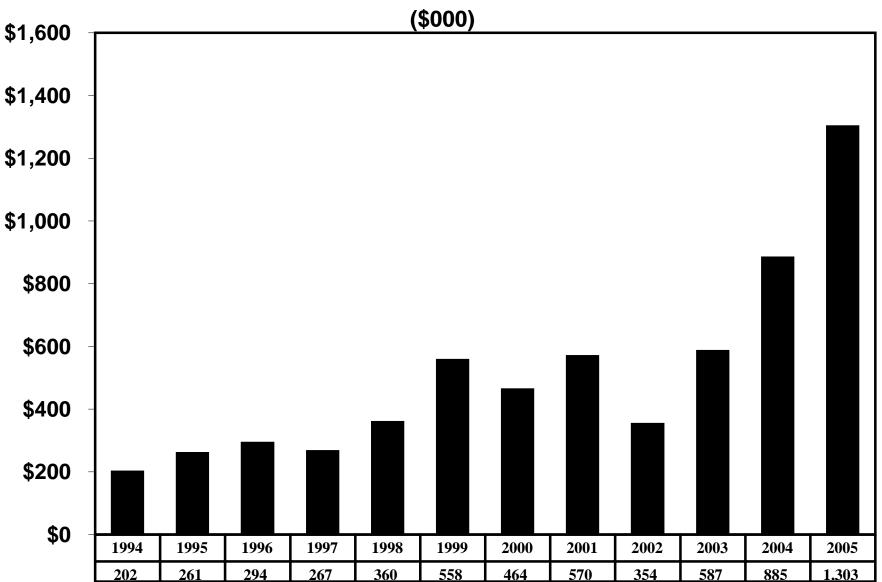
Springfield
Bare Steel Services: 1994 -2005



Lawrence Bare Steel Services: 1994 -2005 (\$000)



Brockton
Bare Steel Services: 1994 -2005



COMMONWEALTH OF MASSACHUSETTS DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL D. T. E. 05-27

Date: May 26, 2005

Responsible: Danny G. Cote, General Manager

AG-2-38 Create a bar graph with the years 1990 to 2005 along x-axis and

Company number of bare steel main abandonments per year along the yaxis. Include all work papers, calculations and assumptions used to calculate the number of bare steel mains abandonments per year.

Response: Page 1 of Attachment AG-2-38 is a bar graph with the years 1993 to 2005

along the x-axis and Company footage of bare steel main abandoned along the y-axis. Page 2 of Attachment AG-2-38 includes the supporting work paper. The source of the historical data for this response comes directly from the Company's Work Order Management System ("WOMS")

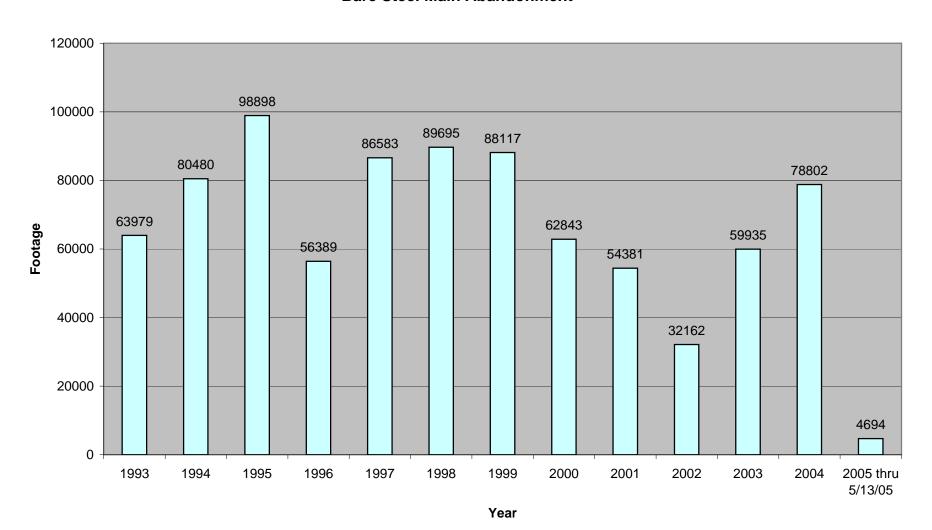
Data for 2005 is through May 13, 2005.

Data is not readily available for 1990-1992.

The data set includes both mains abandoned as well as mains abandoned and replaced.

Further, because WOMS is unable to differentiate between corrosion leaks occurring on unprotected coated steel and cathodically protected coated steel, Bay State's operational management judgment presumes that all abandoned and replaced pipe with an install date prior to 1971 was unprotected steel.

Bay State Gas Company Consolidated Bare Steel Main Abandonment



Bay State Gas Company D.T.E. 05-27 Attachment AG-2-38 Page 2 of 2

Bay State Gas Company Bare Steel Main Abandonments Work Paper Units in Feet

Division	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005 thru 5/13/05
211101011	.000	100.	.000	1000		.000	1000		2001				0, 10,00
Brockton	54145	50467	81993	41874	45054	67432	58874	43256	34577	21473	37068	72543	4372
Springfield	8524	27956	14752	10407	23142	15069	26016	18419	16082	4183	18327	3120	32
Lawrence	1310	2057	2153	4108	18387	7194	3227	1168	3722	6506	4540	3139	290
Total	63979	80480	98898	56389	86583	89695	88117	62843	54381	32162	59935	78802	4694

NOTES: Data from Work Order Management System query 5/13/05.

Data reflects Footage of mains retired, including abandoned and abandoned and replaced.

Work codes used for query include "RTMX" and "MR".

RESPONSE OF BAY STATE GAS COMPANY TO THE SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL D. T. E. 05-27

Date: May 26, 2005

Responsible: Danny G. Cote, General Manager

AG-2-39

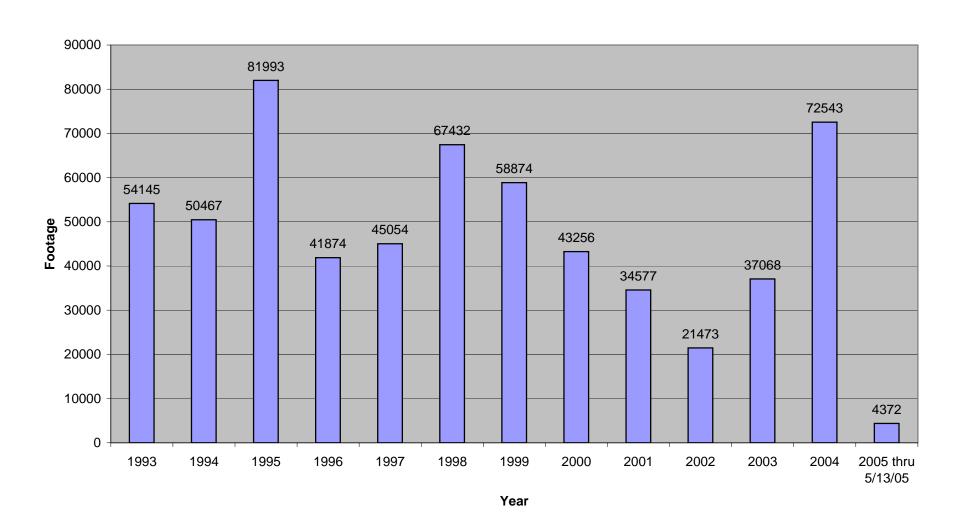
Create bar graphs with the years 1990 to 2005 along x-axis and the numbers of bare steel main abandonments per year along the y-axis for the Company's service territories in the cities of Springfield, Lawrence and Brockton. Include all work papers, calculations and assumptions used to calculate the number of bare steel mains abandonments per year for each of the cities.

Response:

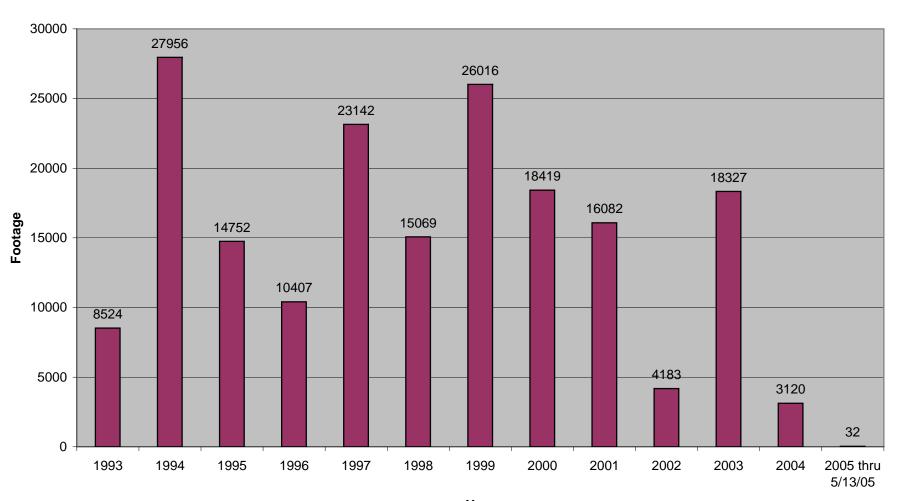
Pages 1-3 of Attachment AG-2-39 are bar graphs with the years 1993 to 2005 along the x-axis and Company footage of bare steel main abandoned along the y-axis for the Brockton, Springfield, and Lawrence Divisions, respectively. Page 4 of Attachment AG-2-39 includes the supporting work paper. The source of the historical data for this response comes directly from the Company's Work Order Management System ("WOMS") Data for 2005 is through May 13, 2005.

The data set includes both mains abandoned as well as mains abandoned and replaced.

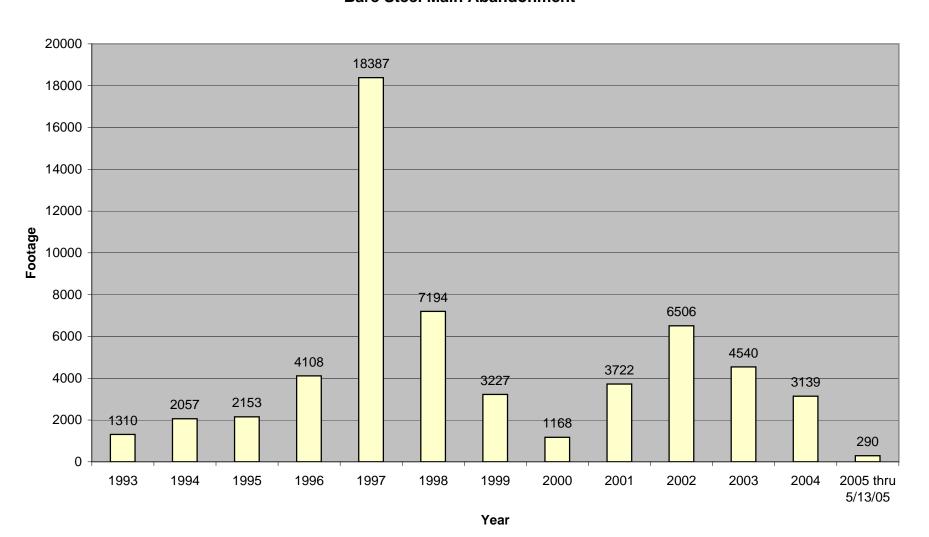
Bay State Gas Company Brockton Division Bare Steel Main Abandonment



Bay State Gas Company Springfield Division Bare Steel Main Abandonment



Bay State Gas Company Lawrence Division Bare Steel Main Abandonment



D.T.E. 05-27 Attachment AG-2-39 Page 4 of 4

Bay State Gas Company Bare Steel Main Abandonments Work Paper Units In Feet

Division	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005 thru 5/13/05
Brockton	54145	50467	81993	41874	45054	67432	58874	43256	34577	21473	37068	72543	4372
Springfield	8524	27956	14752	10407	23142	15069	26016	18419	16082	4183	18327	3120	32
Lawrence	1310	2057	2153	4108	18387	7194	3227	1168	3722	6506	4540	3139	290
Total	63979	80480	98898	56389	86583	89695	88117	62843	54381	32162	59935	78802	4694

NOTES: Data from Work Order Management System query 5/13/05.

Data reflects Footage of mains retired, including abandoned and abandoned and replaced.

Work codes used for query included "RTMX" and "MR".

RESPONSE OF BAY STATE GAS COMPANY TO THE SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL D. T. E. 05-27

Date: May 26, 2005

Responsible: Danny G. Cote, General Manager

AG-2-40 Create bar graphs with the years 1990 to 2005 along x-axis and

Company number of bare steel services abandonments per year along the y-axis for the Company's Springfield, Lawrence and Brockton service territories. Include all work papers, calculations and assumptions used to calculate the number of bare steel service replacements per year.

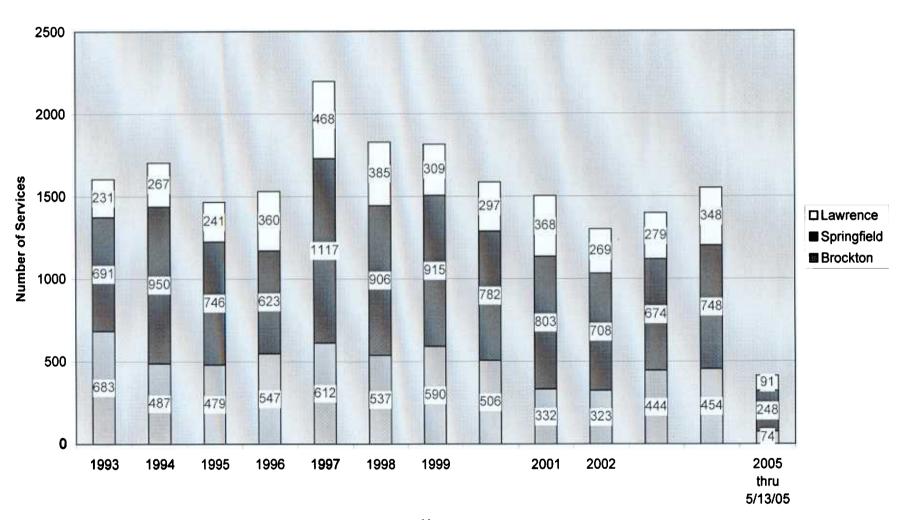
Response:

Page 1 of Attachment AG-2-40 is a bar graph with the years 1993 to 2005 along the x-axis and Company's number of bare steel services abandoned per year along the y-axis for the Brockton, Springfield, and Lawrence Divisions, respectively. Page 2 of Attachment AG-2-40 includes the supporting work paper. The source of the historical data for this response comes directly from the Company's Work Order Management System ("WOMS") Data for 2005 is through May 13, 2005.

Data is not readily available for 1990-1992.

The data set includes both services abandoned as well as services abandoned and replaced.

Bay State Gas Bare Steel Service Abandonments



Bay State Gas Company D.T.E. 05-27 Attachment AG-2-40 Page 2 of 2

Bay State Gas Company Bare Steel Service Abandonments Work Paper

Division	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005 thru 5/13/05
Brockton	683	487	479	547	612	537	590	506	332	323	444	454	74
Springfield	691	950	746	623	1117	906	915	782	803	708	674	748	248
Lawrence	231	267	241	360	468	385	309	297	368	269	279	348	91
Total	1605	1704	1466	1530	2197	1828	1814	1585	1503	1300	1397	1550	413

NOTES: Data from Work Order Management System query 5/13/05.

Data reflects number of services retired, including abandoned and abandoned and replaced.

Work codes used for query included "RTSR" and "SR".

RESPONSE OF BAY STATE GAS COMPANY TO THE SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL D. T. E. 05-27

Date: May 26, 2005

Responsible: Danny G. Cote, General Manager

AG-2-45 Create a bar graph with the years 1990 to 2005 along x-axis and

Company number of coated steel without cathodic protection main abandonments per year along the y-axis. Include all work papers, calculations and assumptions used to calculate the number of these

mains abandonments per year.

Response: Page 1 of Attachment AG-2-45 is a bar graph with the years 1993 to 2005

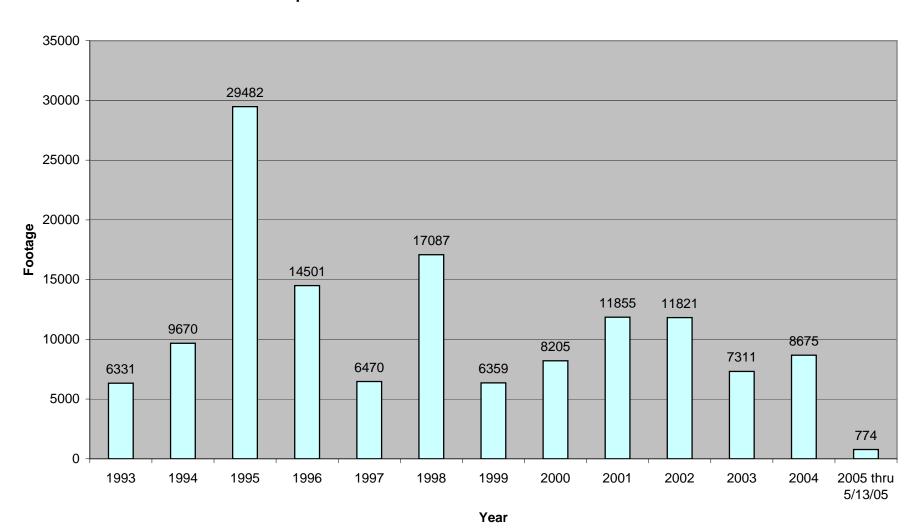
along the x-axis and Company's consolidated footage of unprotected coated steel mains abandoned per year along the y-axis. Page 2 of Attachment AG-2-45 includes the supporting work paper. The source of the historical data for this response comes directly from the Company's Work Order Management System ("WOMS") Data for 2005 is through

May 13, 2005.

Data is not readily available for 1990-1992.

The data set includes both mains abandoned as well as mains abandoned and replaced.

Bay State Gas Company Consolidated Unprotecteed Coated Steel Mains Abandonment



Bay State Gas Company D.T.E. 05-27 Attachment AG-2-45 Page 2 of 2

Division	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005 thru 5/13/05
Brockton	5677	6694	27895	13534	4406	15231	3984	6806	5699	10251	6860	6007	0
Springfield	629	2247	941	792	1984	1452	1266	1392	5648	718	251	2076	774
Lawrence	25	729	646	175	80	404	1109	7	508	852	200	592	0
Total	6331	9670	29482	14501	6470	17087	6359	8205	11855	11821	7311	8675	774

NOTES: Data from Work Order Management System query 5/13/05.

Data reflects Footage of mains retired, including abandoned and abandoned and replaced.

Work codes used for query include "RTMX" and "MR".

RESPONSE OF BAY STATE GAS COMPANY TO THE SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL D. T. E. 05-27

Date: May 26, 2005

Responsible: Danny G. Cote, General Manager

AG-2-46

Create bar graphs with the years 1990 to 2005 along x-axis and the numbers of coated steel without cathodic protection main abandonments per year along the y-axis for the Company's service territories in the cities of Springfield, Lawrence and Brockton. Include all work papers, calculations and assumptions used to calculate the number of bare steel mains abandonments per year for each of the cities.

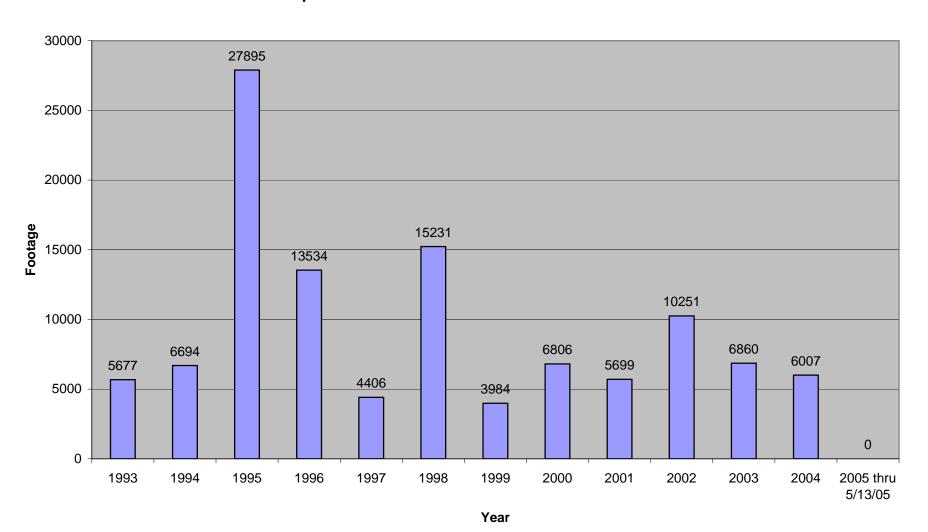
Response:

Pages 1-3 of Attachment AG-2-46 are bar graphs with the years 1993 to 2005 along the x-axis and Company's footage of unprotected coated steel mains abandoned per year for the Brockton, Springfield and Lawrence Divisions, respectively, along the y-axis. Page 4 of Attachment AG-2-46 includes the supporting work paper. The source of the historical data for this response comes directly from the Company's Work Order Management System ("WOMS") Data for 2005 is through May 13, 2005.

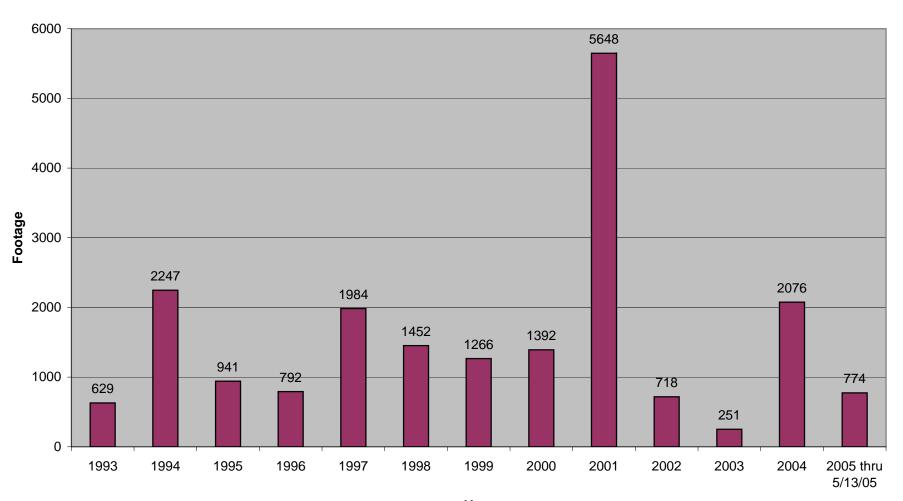
Data is not readily available for 1990-1992.

The data set includes both mains abandoned as well as mains abandoned and replaced.

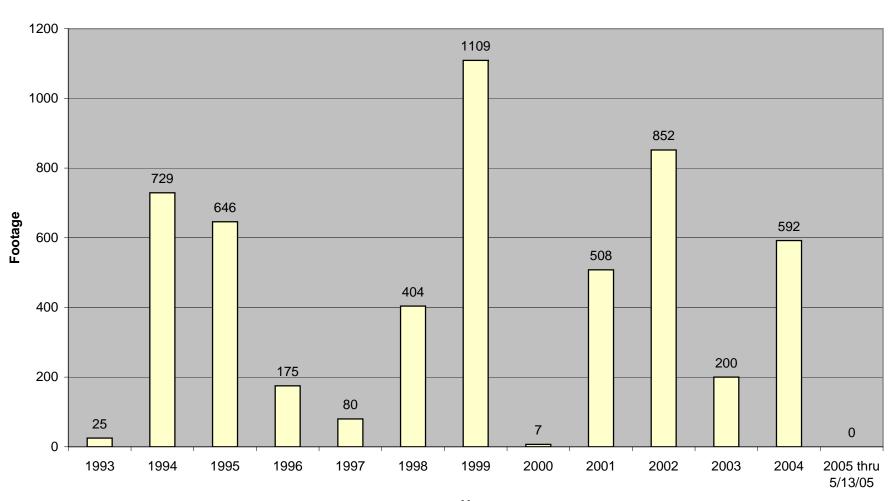
Bay State Gas Company Brockton Division Unprotected Coated Steel Mains Abandonment



Bay State Gas Company Springfield Division Unprotected Coated Steel Mains Abandonment



Bay State Gas Company Lawrence Division Unprotected Coated Steel Mains Abandonment



D.T.E. 05-27 Attachment AG-2-46 Page 4 of 4

Bay State Gas Company Unprotected Coated Steel Main Abandonments Work Paper Units in Feet

Division	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005 thru 5/13/05
Brockton	5677	6694	27895	13534	4406	15231	3984	6806	5699	10251	6860	6007	0
Springfield	629	2247	941	792	1984	1452	1266	1392	5648	718	251	2076	774
Lawrence	25	729	646	175	80	404	1109	7	508	852	200	592	0
Total	6331	9670	29482	14501	6470	17087	6359	8205	11855	11821	7311	8675	774

NOTES: Data from Work Order Management System query 5/13/05.

Data reflects Footage of mains retired, including abandoned and abandoned and replaced.

Work codes used for query include "RTMX" and "MR".

RESPONSE OF BAY STATE GAS COMPANY TO THE SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL D. T. E. 05-27

Date: May 26, 2005

Responsible: Danny G. Cote, General Manager

AG-2-47

Create bar graphs with the years 1990 to 2005 along x-axis and Company number of coated steel without cathodic protection services abandonments per year along the y-axis for the Company's Springfield, Lawrence and Brockton service territories. Include all work papers, calculations and assumptions used to calculate the number of these service replacements per year.

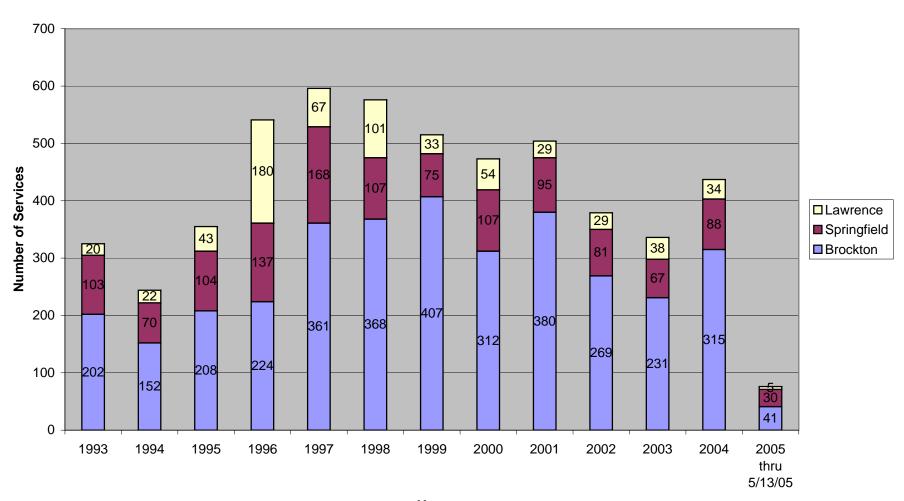
Response:

Page 1 of Attachment AG-2-47 is a bar graph with the years 1993 to 2005 along the x-axis and Company's consolidated number of unprotected coated steel services abandoned per year (broken down by division) along the y-axis. Page 2 of Attachment AG-2-47 includes the supporting work paper. The source of the historical data for this response comes directly from the Company's Work Order Management System ("WOMS") Data for 2005 is through May 13, 2005.

Data is not readily available for 1990-1992.

The data set includes both services abandoned as well as services abandoned and replaced.

Bay State Gas Company Consolidated Unprotected Coated Steel Service Abandoment



Bay State Gas Company D.T.E. 05-27 Attachment AG-2-47 Page 2 of 2

Bay State Gas Company Unprotected Coated Steel Service Abandonments Work Paper

Division	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005 thru 5/13/05
Brockton	202	152	208	224	361	368	407	312	380	269	231	315	41
Springfield	103	70	104	137	168	107	75	107	95	81	67	88	30
Lawrence	20	22	43	180	67	101	33	54	29	29	38	34	5
Total	325	244	355	541	596	576	515	473	504	379	336	437	76

NOTES: Data from Work Order Management System query 5/13/05.

Data reflects number of services retired, including abandoned and abandoned and replaced.

Work codes used for query included "RTSR" and "SR".

RESPONSE OF BAY STATE GAS COMPANY TO THE SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL D. T. E. 05-27

Date: May 26, 2005

Responsible: Danny G. Cote, General Manager

AG-2-50 Provide the total number of miles of coated steel main without cathodic

protection in the Company's service territories.

Response: The total number of miles of coated steel main without cathodic protection

as of December 31, 2004, was 106 miles. Please see Bay State's response to AG-2-53. In that response, Bay State notes that it has impressed 460 miles of pre-1971 coated steel with cathodic protection, and the remaining 106 miles is unsuitable for remediation by cathodic

anode.

RESPONSE OF BAY STATE GAS COMPANY TO THE SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL D. T. E. 05-27

Date: May 26, 2005

Responsible: Danny G. Cote, General Manager

AG-2-51 Provide the total number of cathodically protected coated steel mains in the Company's service territories and the cost per mile for the cathodic protection.

Response: Bay State has 2,034 miles of cathodically protected coated steel main in Massachusetts as of December 31, 2004.

Bay State spent \$320.63 per mile to cathodically protect coated steel main in Massachusetts in 2004.